

# A Primer on Alternative Transportation Fuels

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# Executive Summary

A review is undertaken of several approaches to producing alternative transportation fuels using feedstocks that are under the control of the United States. The objective of the review is to provide the non-specialist reader with a general understanding of the several approaches, how they compare regarding process energy efficiency, their individual abilities to provide for national transportation fuel needs, and their associated capital costs. It is noted that, in principle, vehicle missions determine fuel and propulsion plant requirements rather than the other way around. In reality, of course, there is a tradeoff among desired mission capabilities and fuel and propulsion plant technologies.

The review results suggest these conclusions about alternative transportation fuels:

- If necessary, the United States can manufacture the transportation fuels it needs.
- The capital investments needed to manufacture fuels beyond petroleum will be substantial, regardless of the particular alternative fuel selected. In this regard, the steam reformation of methane (SMR) processes, because of their higher efficiencies and substantially lower capital costs, would seem to warrant special attention. The associated fuels are not carbon free or carbon neutral.
- The capital investments associated with the manufacture of renewable—carbon free or carbon neutral—fuels will be especially large.
- Serious commercial investment in alternative fuels, in contrast to standard petroleum-based fuels, will be difficult to obtain as long as low-cost petroleum is available.

True comparative evaluation of transportation fuel inextricably requires consideration of the vehicle and mission that the fuel is intended to power. A mission can place significant volume and weight constraints on its combined (power plant plus fuel) system for transportation. Consequently, power density, energy density, and propulsion plant energy efficiency become essential metrics for comparing various alternative transportation fuels. This review commences with a brief discussion regarding the relationship between mission requirements and vehicle kinematics and how these determine the requirements for fuel and propulsion plants. This is followed by a review of the characteristics (e.g., torque, horsepower, weight, volume, and fuel consumption) of several of the most popular engines, where it is shown that the various engines generally are best suited to different missions. We then focus our attention on fuel approaches where the required feedstocks are within the direct control of the United States. The specific topics discussed are: batteries and fuel cells, hydrogen, coal to liquid, natural gas and gas hydrate-derived fuels, bio-derived fuels, CO<sub>2</sub>-derived fuels, and oil shale.

For batteries and fuel cells, this report starts from a broad discussion of considerations related to the selection of the entire propulsion plant, including fuels and engines. The Ragone chart of specific energy vs. specific power is introduced as a comparative means of placing the various propulsion plants into perspective. The vehicle mission places

simultaneous demands on specific power and specific energy. The power plant must be able to meet these independent requirements. Hence, the mission requirements when placed on the Ragone chart must lie within the performance characteristics of the selected technology. Each of the technologies considered occupies a particular area on the chart. The chart shows that, for all the available propulsion plants considered, the specific energy of the plant decreases as the specific power of the plant increases. The internal combustion power plants considered had the most robust capability to support both high specific power and high specific energy. The electric power sources considered in the chart include batteries and fuel cells. Importantly, the batteries and fuel cells were shown to have limited specific energy at the required specific power. As a result, there has been a very limited overlap between battery and fuel cell power and energy characteristics and transportation vehicle mission requirements.

The problem with currently available or near-term battery and fuel cell technologies is that either the available energy or the available power is inadequate for the vehicle mission. In some cases, where the mission requires high power for only a small fraction of a vehicle's mission, the introduction of an auxiliary pulse power system becomes viable. In this case the pulse power system can be "charged" at a low power that is compatible with the mission average power requirements. For a small fraction of the mission the pulse power system will deliver the necessary high power but low total energy. It is possible that battery and fuel cell technology combined with electric motors may progress to the point where this approach is viable for passenger vehicles where high power is typically required for less than ten percent of a vehicle mission. This could be an important development, because passenger vehicles account for about half of U.S. oil consumption. However, for high-energy, high-power missions, the chart shows that batteries and fuel cell are disadvantaged relative to the internal combustion engines considered. It seems unlikely that the disadvantage can be overcome for high-performance DOD, commercial, and industrial missions involving transportation fuels. As a result, internal combustion propulsion plants will likely remain the plants of choice for these missions for the foreseeable future, and with a concomitant essential need for "petroleum grade" fuel.

Regarding transportation fuels themselves, a central objective is to provide some sense of the scale of the various undertakings, such as the capital investments that would need to be made to bring the various approaches to the point of providing transportation fuel independence and the impact that would result on the various feedstocks. Hence, the alternative fuel approaches considered include: hydrogen production, creation of synthesis gases from various feedstocks followed by a fuel synthesis process, enzymatic production of ethanol, the use of biomass oils for biodiesel production, fuel synthesis using atmospheric carbon dioxide as a feedstock, and the exploitation of oil shale.

In order to undertake a stressful assessment of an alternative fuel's viability as a solution to the transportation fuels problem, each alternative fuel was evaluated according to its ability to provide a fuel product with the energy equivalent of the  $13.4 \times 10^6$  barrels per day (BPD) of petroleum currently used by the U.S. transportation system. In that regard, it was noted that, for the typical passenger vehicle, only about 18% of the fuel energy it consumes is actually used for the propulsion of the vehicle, with most of the remainder lost primarily as waste heat. Since passenger vehicles account for about two-

thirds of the transportation fuel consumed, the energy that is actually required by vehicle kinematics is much less than the number mentioned above. A significant improvement in propulsion plant energy efficiency would reduce significantly the amount of transportation fuel needed thereby reducing—in a larger sense—the need for alternative fuel.

A comparison of the findings for the various alternative fuel processes approaches considered is presented succinctly in table ES1 (next page). This table provides estimates of the process efficiencies and rough order of magnitude (ROM) estimates of capital costs associated with production of hydrogen and the liquid fuels considered, at a scale needed to produce  $13.4 \times 10^6$  barrels per day (BPD) of oil equivalent product. The process energy efficiency was defined as the calorific energy content of the fuel product produced by the process divided by the sum of the calorific energy content of the feedstock consumed, plus any additional energy required to enable the process. The table is ordered by increasing capital costs, except for oil shale, which is qualitatively different from the other entries.

As can be seen from table ES1, there are potentially many processes by which alternative fuels can be produced with the energy content required by the U.S. transportation system. There is a large spread in the energy efficiencies of the processes, ranging from 70% for SMR production of hydrogen to 18% for gasoline production from atmospheric carbon dioxide ( $\text{CO}_2$ ). Similarly, there is a large spread in the estimated capital costs associated with the various processes, ranging from a low of about 173 billion dollars for hydrogen production using SMR to a high of about 4 trillion dollars for gasoline production from atmospheric  $\text{CO}_2$ . It is clear from the table that increasing capital costs tend to correlate with decreasing energy efficiencies. This is not an unexpected result.

Several of the processes shown in table ES1 can be eliminated for reasons of impracticality towards meeting the scalability goal. Corn-based ethanol and biodiesel have been included simply to show where they fall in the hierarchies of efficiency and cost. In reality, while both fuels may have important niche roles to play, neither of them is a serious candidate for solving the national transportation fuels problem. The necessary feedstocks are simply not available. It is also recommended that hydrogen be set aside from consideration, even though it has the lowest capital costs when produced by SMR techniques. It could be used as a fuel if it were absolutely necessary and could be produced in adequate quantity to meet national transportation fuel needs. If produced by nuclear or solar-powered thermochemical means or by electrolysis it would produce no greenhouse gas  $\text{CO}_2$ . However, the logistical problems associated with the cryogenic systems or high-pressure systems required to employ hydrogen as a general-purpose transportation fuel make its use as a general-purpose transportation fuel or as a fuel for most DOD vehicles problematic.

Process	Process energy efficiency	ROM capital cost (billions of dollars)	Comment
Steam reforming of methane (SMR) to hydrogen	70%	170	Commercial process,* doubles NG consumption
Biodiesel	35%	200	Commercial process***
SMR to methanol	60%	250	Commercial process*
SMR to gasoline via methanol	54%	300	Commercial process*
Corn ethanol	46%	400	Commercial process***
Hydrogen by biomass gasification	46%	500	Commercial process**
Hydrogen by coal gasification	44%	500	Commercial process,* doubles coal consumption
Coal to liquid	44%	900	Commercial process,* quadruples coal consumption
Biomass to liquid	47%	900	commercial processes**
Hydrogen by thermochemical	50%	1,000	Process under development*
Lignocellulose ethanol	41%	1,500	Process under development**
Hydrogen by conventional electrolysis	25%	2,000	Commercial electrolyzer, 3 <sup>rd</sup> gen nuclear reactor*
Atmospheric CO <sub>2</sub> to gasoline	18%	4,000	Commercial processes + 3 <sup>rd</sup> gen nuclear reactor*
Oil shale surface retort approach	?	1,000	Involves massive mining and disposal
Shell oil shale <i>in situ</i> retort approach	Less than 50%	Greater than 500	electric power plant only*

**Table ES1.** Summary estimates of the process efficiencies and ROM capital costs associated with production of hydrogen and several liquid fuels at a scale to produce 13.4x10<sup>6</sup> BPD Oil equivalent product.

Key: \*not renewable but can, in principle, meet the BPD goal, \*\*renewable but available feedstock cannot sustainably meet BPD goal, \*\*\*renewable but available feedstock cannot meet BPD goal.)

Among the remaining alternative fuel processes identified here, the SMR processes are found to be the most energy efficient and have the lowest capital costs. They can also produce a variety of different fuels including hydrogen, alcohols, and hydrocarbons. A negative aspect is that their use would double the consumption of natural gas and add substantially to CO<sub>2</sub> production. With regard to the increased consumption of natural gas, the recent advances in gas production using hydraulic fracture of shale and the vast reserves of gas hydrates that are believed to exist may play a role. The advances in hydraulic fracture of shale are estimated to increase the U.S. potentially available natural gas resources by one-third, resulting in about 100 years of natural gas supply at current usage rates. If gas hydrates could be safely and economically obtained, they would potentially provide a large supply of methane thereby allowing the manufacture of transportation fuels for generations. Unfortunately, at this time the viability of gas hydrates as a serious source of methane is unknown and it will likely be decades before their viability is quantified. Regarding the production of CO<sub>2</sub>, if it is deemed inappropriate to release it into the atmosphere, then the fact that it would be produced at large central sites would simplify its capture. Upon capture it could be processed into additional fuels by methods similar to those to be described for fuel production from atmospheric CO<sub>2</sub>. This would be an expensive undertaking as can be seen from table ES1. However, it would minimize CO<sub>2</sub> production during fuels manufacture and also reduce the amount of methane needed. Ultimately, of course, the CO<sub>2</sub> would be released into the atmosphere upon fuel combustion or reforming. As an alternative, the captured CO<sub>2</sub> could also be sequestered if such schemes are allowed. Whether large-scale sequestration of CO<sub>2</sub> will be viable is currently a matter of study. It is clear that, while SMR processes could supply the needed transportation fuels for an extended period, a number of issues must be resolved before the SMR approach to alternative fuel production can be properly assessed for implementation.

The next process that shows up as being most process energy efficient and least capital intensive is the conversion of coal to liquid fuels (CTL). This process is considerably more costly than the SMR processes. Nevertheless, it too can produce a variety of fuels, including hydrogen, alcohols and hydrocarbons. Its use would nearly quadruple the consumption of coal and reduce the lifetime of the U.S. coal supply from the current value of 280 years to about 80 years (assuming that transportation fuel use did not increase from its current value). The use of CTL would double CO<sub>2</sub> production. As with the SMR processes, at considerable expense that portion of the CO<sub>2</sub> that results from the CTL process could be captured at the central production sites and converted to additional transportation fuel, thereby reducing the amount of coal that must be mined. Of course, this approach would increase the demands on the supply of uranium in the likely event that nuclear energy would provide the power needed to convert the captured CO<sub>2</sub> into a transportation fuel. If permitted, here also the captured CO<sub>2</sub> could be sequestered. In this regard, one should keep in mind that after about 80 years one would have sequestered about half the carbon in the U.S. coal supply in the form of gaseous CO<sub>2</sub>. As with the SMR processes, the CTL process could supply the needed transportation fuels for an extended period. However, a number of issues must be resolved before the CTL approach to alternative fuel production can be properly assessed.

The biomass to liquid fuels (BTL) process comes in at about the same process energy efficiency and capital cost as does the CTL process. The BTL process is generally

described as renewable, because the source can be regrown. However, if it is to be sustainable, then the biomass harvest must be limited by the rate of regrowth of the biomass. Furthermore, there are other uses for the biomass that further limit the amount of biomass that can be used for alternative fuel production. It has been estimated that about 1.4 billion tons per year of biomass can be made available, in a sustainable fashion, for the production of alternative fuels. If this biomass were converted into fuel in the BTL process, it could provide for about 35% of the current transportation fuel needs. Thus, a full solution of the transportation fuels problem via the BTL approach does not seem to be viable. Of course, a 35% solution would be a significant contribution. The capital cost associated with the 35% solution would be about 300 billion dollars rather than the 900 billion dollars indicated in table ES1 for a full solution. In this regard, it should be recalled that the SMR processes indicate that a full solution may be available for a capital investment of about 300 billion dollars. In support of the BTL process it is often suggested the BTL approach is CO<sub>2</sub> neutral, because the carbon in biomass comes from the atmosphere and is returned to the atmosphere upon the combustion of the BTL fuel. This statement is true to the extent that the energy to make the biomass comes from the sun. However, to the extent that fossil fuel is required to grow/harvest the biomass, the statement is not true. As with the other processes, a number of issues must be resolved before the BTL contribution to alternative fuel production can be properly assessed.

The next process to appear in the efficiency and capital cost sorting is lignocellulosic ethanol production. This process attempts to break down the cellulose and hemicellulose in biomass into fermentable sugars. This process is still under development and is much more difficult than the well-developed corn ethanol process. However, if successful, it has the advantage that it can access a much larger feedstock than can the corn ethanol process. In order to function in a sustainable fashion, it would target the same 1.4 billion tons of biomass as does the BTL process. This amount of biomass used as feedstock for the lignocellulosic ethanol process would yield about 30% of the ethanol required for a full solution. The capital investment required is estimated to be about 500 billion dollars. The situation regarding carbon neutrality is the same as for the BTL approach; the process has yet to be demonstrated at a scale where its contribution to alternative fuels can be properly assessed.

The fuel synthesis schemes with the lowest energy efficiency and the highest capital cost involve the use of atmospheric CO<sub>2</sub> as a feedstock. The process involves absorbing CO<sub>2</sub> from the atmosphere and recovering it for reaction with hydrogen in order to make methanol. The process could stop with methanol, or the methanol could be further processed to make a higher energy density fuel such as gasoline. The recovery of CO<sub>2</sub> and the production of the necessary hydrogen are energy intensive and would likely involve the use of nuclear reactors. The various steps of the process have been tested and involve well-understood technologies. In principle, the process should be capable of producing the quantities of fuel needed to solve the transportation fuel problem. For the case considered herein, this would require about 1600 nuclear reactors each providing a thermal power of about three gigawatts. The total capital cost for the production plants is estimated to be about four trillion dollars. Since the feedstocks for this process are atmospheric CO<sub>2</sub> and water, and the supplemental power is from nuclear energy, the process is CO<sub>2</sub> neutral. However, the uranium consumption resulting from the large number of nuclear reactors would be substantial and would likely deplete the reserves of

low-cost uranium ore in a few decades. The long-term viability of such a process would likely involve the introduction of advanced reactors, and ultimately of breeder reactors. Similar approaches could be applied to converting smokestack CO<sub>2</sub> to fuel where the higher CO<sub>2</sub> density would make the collection of CO<sub>2</sub> easier. However, because the capital costs for fuel production are dominated by the recovery of the absorbed CO<sub>2</sub> and the production of the required hydrogen, for the same amount of fuel the plant capital costs would be similar to that given above for fuel production from atmospheric CO<sub>2</sub>. There are clearly many issues that need to be resolved regarding this approach to alternative transportation fuels.

The final topic considered was that of transportation fuel from oil shale. Oil shale processing is qualitatively different from the schemes discussed above. The organic carbon that would form the basis of fuels is obtained by heating the shale to about 700 °F and driving a liquid crude oil from the shale. This heating is performed in a vessel called a retort and the process is called retorting. The crude oil obtained is collected and sent to a refinery where it is turned into usable fuels much as is done with conventional petroleum. Retorting is done on the surface or *in situ*. It is estimated that U.S. oil shale formations could supply current U.S. transportation fuel needs for more than 140 years. However, the process for obtaining oil shale crude is very energy intensive. There are no recent studies that provide current data regarding the expected capital costs associated with producing shale oil crude. Studies done in the 1980s, when scaled to 2005 dollars, suggest that the capital costs associated with producing 13.4x10<sup>6</sup> BPD of oil shale crude by surface retorting would be about one trillion dollars. Regarding the capital costs associated with the *in situ* approach, in recent years, Shell Oil has been studying an *in situ* retorting approach in which the heat needed to drive out the oil shale crude is provided by electric heaters placed within the shale deposits. This approach would avoid having to mine the shale. It can be shown that the electrical power system needed to provide the heat necessary to produce 13.4x10<sup>6</sup> BPD of oil shale crude would itself have a capital cost in excess of 500 billion dollars. There are many environmental concerns (e.g., ground water contamination) associated with producing oil shale crude.

Finally, it is important to note that, on the basis of national security needs, the DOD could argue to use appropriated funds to pay for the development of an alternative fuel to supply its two percent of national transportation fuel usage. There are several methodologies that could supply DOD transportation fuel needs. However, such an undertaking should be approached with great caution. If DOD were to select a scheme that is not viable for the larger transportation system then DOD will be left with a costly proprietary system, will be unable to benefit from competitive forces in the larger marketplace, and could find itself short of fuel in a time of national emergency. It is certainly not clear at this time which is the best alternative fuel approach for DOD and for the nation. It will likely take decades to sort this out. DOD should be a participant in a national effort to clarify the choices from a perspective of mission requirements—to ensure that these requirements will be met—since it could be impacted substantially by the outcome.



# 1. Introduction

The Energy Information Agency (EIA) estimates that the United States presently imports 58% of its oil (petroleum) and that this will grow to about 68% by 2030.<sup>1</sup> This fact, combined with the recent escalation in world oil prices, has led to renewed interest in alternative fuels that might reduce or eliminate the growing dependence on foreign oil sources. Of particular concern are the applications that power the U.S. transportation system. Table 1 summarizes U.S. oil usage for 2007.

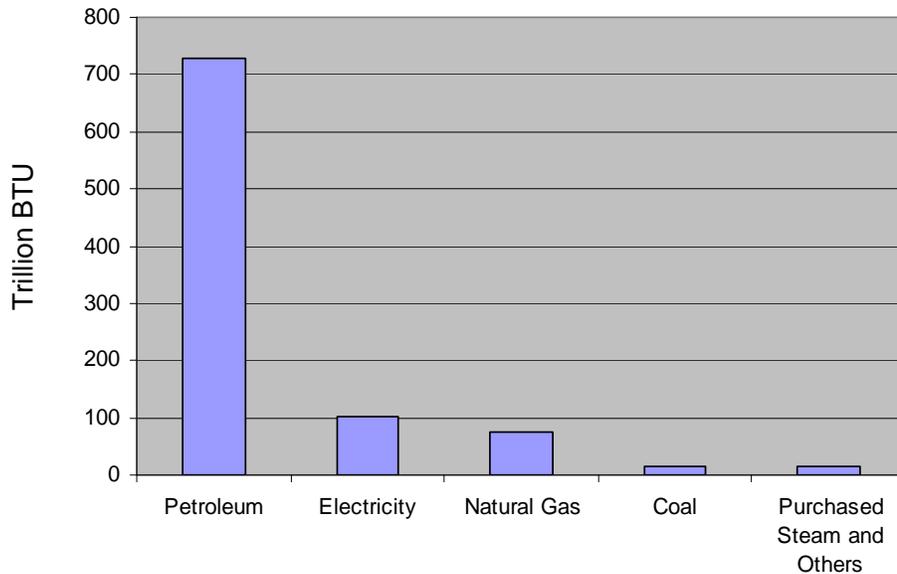
Fuel Use	Amount (million barrels per day)
Motor Gasoline	9.29
Jet Fuel	1.62
Distillate (highway)	2.36
Distillate (ships)	.147
Distillate (Other)	1.69
Residual Fuel	.72
Other	4.82
Total	20.65

**Table 1.** U.S. oil usage for 2007 (Source: Annual Energy Outlook 2009 table 20, Energy Information Agency “Sales of distillate fuel oil by category 2009.”)

It can be seen from table 1 that about 65% (13.4 million barrels per day) of U.S. oil consumption relates to transportation fuels. This number is somewhat misleading in that the energy conversion efficiency of the typical transportation plant is about 18% (see figure A1 of appendix A). Thus, the energy that is actually needed for transportation propulsion is equivalent to about 2.4 million barrels of oil per day (BPD). The remaining 11 million BPD emerges mostly as waste heat due to the underlying efficiency of the energy conversion process. In this paper we will use 13.4 million BPD as the goal that alternative fuels must meet. However, it should be kept in mind that a radical improvement in the energy efficiency of propulsion power plants would markedly change the transportation fuels requirement.

The Department of Defense (DOD) is especially dependent on petroleum. Figure 1 summarizes the DOD energy usage for 2005.

## US Department of Defense Energy Consumption, Fiscal Year 2005



**Figure 1.** DOD energy usage during 2005 (Source DESC Fact Book FY 08).

It is clear from figure 1 that petroleum is the dominant energy source for DOD. The DOD use of petroleum is primarily associated with transportation fuels. Since a barrel of oil has an energy content of about 5.8 million BTU, it follows from table 1 and figure 1 that DOD is responsible for about 2% of U.S. petroleum consumption. This percentage is sufficiently small that DOD can reasonably expect to have access to the petroleum resources needed to meet its mission in a national emergency. However, DOD cannot be complacent regarding oil supplies. DOD must purchase the oil it uses and is therefore directly impacted by oil prices. More importantly, the missions that DOD will be tasked to undertake are likely to be impacted profoundly by international developments in the area of energy supplies. Furthermore, DOD has a big stake in the outcome of any attempt to move the nation to an alternative fuel. For example, some of the alternative fuels under consideration would be ill suited for DOD use, as will be discussed in sections 5 through 10. There are other solutions that could meet DOD needs but would not scale to the larger national transportation fuel needs. If DOD selected one of these solutions it would put itself in the position of having to maintain a DOD-unique fuels infrastructure that would not benefit from the potential efficiencies of the larger national fuels infrastructure. Therefore, the large and growing dependence on imported oil and the growing national interest in alternative fuels are matters of both economic and military concern. This has led to increased interest within DOD and other agencies regarding whether and which

alternative fuels could be produced from U.S. feedstocks on a scale that could lead to energy independence for the United States.

From a policy and planning perspective, one of the difficulties with alternative fuels relates to the great variety of possibilities that are potentially available. Each of these possibilities has its own community and literature (some of which goes back 100 years or more). While there is a great deal known about most of the alternative fuels, it is difficult to find discussions that attempt to place various possibilities within the context of the national transportation fuel problem and with respect to each other. This report will attempt to make some progress in this regard. The objective here is to provide some sense of the scale of the various undertakings, such as the capital investments that would need to be made to bring the various approaches to the point of providing transportation fuel independence and the impact that would result on the various feedstocks. The paper is intended for the non-specialist for whom a broad understanding of alternative fuels would be helpful. In general, the paper will not delve into special technical issues, such as the best catalyst to employ in a particular situation. We will assume such matters can be resolved, and that it is technically feasible to produce the fuel. This report will provide rough order of magnitude (ROM) estimates of some of the consequences of moving beyond technical feasibility to a national solution that provides transportation fuel independence. A detailed discussion of the underlying chemistry and physics can be found in Probst and Hicks.<sup>2</sup>

Transportation fuels are especially challenging, because they are typically carried by the vehicle that they power. This places significant volume and weight restrictions on the fuels and power plants that can be considered for transportation purposes. As a result, power density, energy density, and propulsion plant energy efficiency become essential metrics for comparing various alternative transportation fuels. We will focus our attention on approaches where the required feedstocks are within the direct control of the United States. The specific alternative fuel applications that we will discuss are: batteries and fuel cells, hydrogen, coal to liquid, natural gas and gas hydrate-derived fuels, bio-derived fuels, CO<sub>2</sub>-derived fuels, and oil shale. The place to begin such a discussion, however, is not with the fuels but with the mission requirements to which the fuels must respond. Section 2 will provide a brief discussion of some of the ways in which mission requirements influence fuel and power plant considerations. Section 3 is an overview of the characteristics (e.g., torque, horsepower, weight, volume, and fuel consumption) of several mission-essential engines. Comparative assessment of how the various engines generally are best suited to different missions, in section 4, includes discussion of the electric motor engine and the status of batteries and fuel cells in that context. We then focus our attention on the alternative fuel approaches, in sections 5 through 10. In section 11, the review findings are summarized and conclusions are offered.

## 2. Mission Requirements that Drive System Considerations

While this is not a technical paper, a few basic technical concepts are needed for context. (It is a gratifying demonstration of the power of physics and chemistry that one can make serious progress evaluating alternative fuels by employing just a few simple concepts.) The most elementary concept of importance to this paper is that of mass. By definition, mass relates the motion of an object to a force applied to that object (as in “force equals mass times acceleration”). The subject of transportation fuels is ultimately about the ability to accelerate a vehicle of mass  $M$  to some desired speed (velocity)  $V$ , within some specified time and to dynamically control the speed so as to accomplish a desired mission. That mission may be as simple as moving a cargo from one point to another or as complex as conducting air combat operations. It is the mission that determines the dynamics required of a specific vehicle. These dynamics are independent (except for their mass) of the propulsion plant and the fuel that powers that plant. In this regard, a simplified dynamical model that relates mission requirements (e.g., required acceleration, required cruising speed, mission duration, vehicle mass and volume) to power plant properties (e.g., horsepower, weight, and volume) is useful. Such a model is presented in appendix A (A Simple Model for Vehicle Kinematics) for the case of land vehicles and some aspects of seagoing vehicles. We will apply this model to several vehicle types in order to gain some insight into the relationship between mission requirements and propulsion plant requirements.

At the level of discussion appropriate to this paper, vehicle dynamics can be broken into two phases, an acceleration phase that moves a vehicle from one velocity to another and a cruising phase that involves motion at a constant velocity. Acceleration capability is usually a stated requirement in the performance specifications for a vehicle. In the case of acceleration from a stopped position, the most important forces are usually the inertial force, the gravitational force, and the rolling force. The rolling force results from energy that is lost during material deformation (e.g., of tires, treads, and pavement) as a vehicle moves. This force is approximately proportional to the weight of the vehicle and, therefore, explicitly involves the gravitational force. Equations (A2) and (A3) of appendix A are helpful in gaining insight into the impact of acceleration requirements on propulsion plant requirements. From these equations it is straightforward to estimate quantities such as horsepower, time required to reach a particular velocity, and the effective energy used during the acceleration process. The effective energy is a kinematic outcome of the mission requirements and is not the energy used by the power plant. The effective energy and the power plant energy are usually related by the efficiency of the propulsion system.

As one might expect, there is often a tradeoff between a desired mission capability and the ability of technology to provide for that capability. In this regard, table 2 provides predictions for several land vehicles of the power and the effective energy that must be provided by the propulsion shaft when the requirement is to accelerate from a stop to 60 mph (27 m/s) in 6 seconds over level asphalt. The table also gives the time to reach 60

mph and the energy required to do so when the acceleration is accomplished using the horsepower that is actually available to each vehicle. The vehicles have been selected to cover the range from personal automobiles to heavy armored military vehicles. The vehicle characteristics used to construct table 2 are found in table A.1. The type of propulsion plant that was chosen for the various vehicles is indicated by parentheses in column 1. The effective energy that the chosen power plants must deliver in order to achieve 60 mph is given in the last two columns.

Vehicle	Vehicle weight (pounds)	Effective horsepower needed for 0 to 60 mph in 6 s	Available horsepower (neglecting driveline loss)	Time(s) to go from 0 to 60 mph with available horsepower	Effective energy (MJ) for 0 to 60 mph in 6 s	Effective energy (MJ) to achieve 60 mph using available horsepower
Tesla Roadster (electric)	2723	215	288	4.4	.48	.48
Honda Accord (gasoline)	3300	252	270	5.76	.58	.58
Jeep GC (gasoline)	4470	363	195	11.5	.79	.83
Hummer (diesel)	6600	520	240	12.5	1.16	1.24
MRAP (diesel)	38,000	2887	330	67	6.2	9.2
Abrams tank (gas turbine)	140,000	11,661	1500	103	24	58

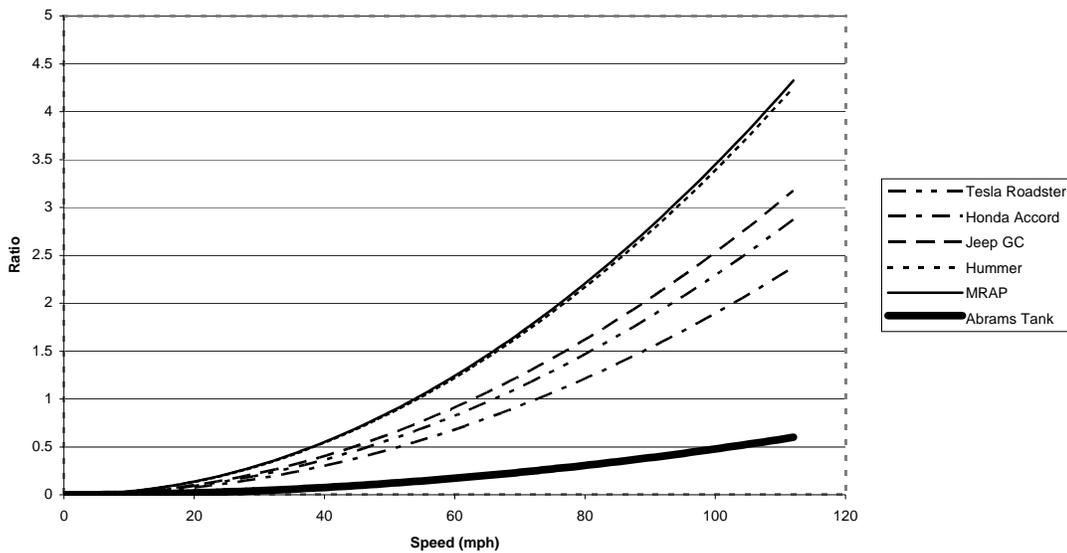
**Table 2.** For several land vehicles, the horsepower and effective energy needed to go from 0 to 60 mph in 6 seconds and also the time to reach 60 mph with the “as-built” horsepower and the effective energy required to do that. The acceleration occurs on a level asphalt surface.

Of the vehicles considered, only the electric (Tesla Roadster) and the gasoline (Honda Accord) actually have the horsepower required to travel from 0 to 60 mph in 6 seconds. The other vehicles are underpowered to meet this objective. The last two columns compare the energy (in Mega Joules) needed to accomplish the acceleration in the two cases considered. The last two columns are essentially the same for the Roadster through the Hummer. This is because the energy needed to overcome the rolling force is small compared to the kinetic energy that was imparted to the vehicles. However, there is a notable difference in the last two columns for the MRAP and the Abrams. This is due to the large rolling force energy loss that results from the weight of the vehicles and the long times that are needed to accelerate these vehicles to 60 mph using the available horsepower. The third column demonstrates the impact on horsepower if a 6-second

acceleration time is imposed as a mission requirement. For the MRAP (which can travel at 60 mph) meeting a 6-second requirement would require a nine-fold increase in the “as-built” engine power, mass and volume. For the Abrams tank, it would require an eight-fold increase in the as procured engine power, mass, and volume. The heavy armor requirements associated with and the volumes available to these vehicles are not compatible with a six-second requirement using available propulsion technologies. It is straightforward to show from eq. (A2) that the 1500 horsepower Abrams tank can achieve a speed of about 20 mph in 6 seconds. (It should be noted here that, while the Abrams tank has the horsepower needed to reach 60 mph, it is restricted to speeds less than 42 mph.)

The acceleration calculations summarized above made use of the fact that the desired speed was achieved in distances that were short enough that the drag force had not become important to the energy consumption. In the cruise phase, however, the drag force usually plays an essential role. For land vehicles, one can gain some sense of the relative importance of the drag force and the rolling force by examining the ratio of drag force to rolling force versus velocity. Figure 2 displays this ratio for the vehicles considered in table 2 in the case of travel on asphalt roads.

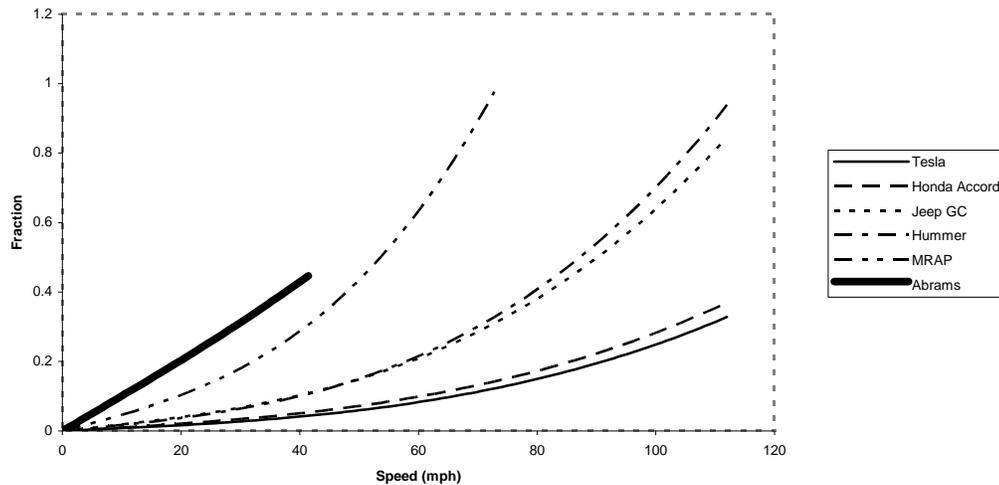
Figure 2. Ratio of drag force to rolling force vs speed (mph) for several vehicles



It is clear from figure 2 that the force that ultimately determines the velocity will vary dependent on the velocity and on the vehicle and its mission. For example, the drag force is not important for velocities of interest to the Abrams tank. For the other vehicles, the ratio becomes unity for velocities between about 50 mph and 70 mph. Over their speed ranges, the other vehicles must take into account both the drag force and the rolling force when traveling over an asphalt surface. This could change if the surface were to change. For example, if the MRAP calculation were done for travel on soft sand, then the rolling force coefficient would increase by about an order of magnitude due to the compressibility of the sand. In that case, the rolling force would dominate the drag force for all speeds of interest to the MRAP.

Equation (A5) provides an expression for the horsepower required to maintain a vehicle at a particular speed during the cruising phase. In order to get a sense of that requirement relative to the horsepower requirement to provide for vehicle acceleration, it is informative to consider the ratio of the horsepower that is needed to maintain a vehicle at a particular speed over an asphalt surface to the horsepower available to that vehicle. This is done in figure 2 for the vehicles considered above. To obtain the absolute horsepower one multiplies the numbers in figure 2 by the available horsepower listed in table 2.

**Figure 3. Fraction of available horsepower needed to maintain speed vs speed (mph) for several vehicles**

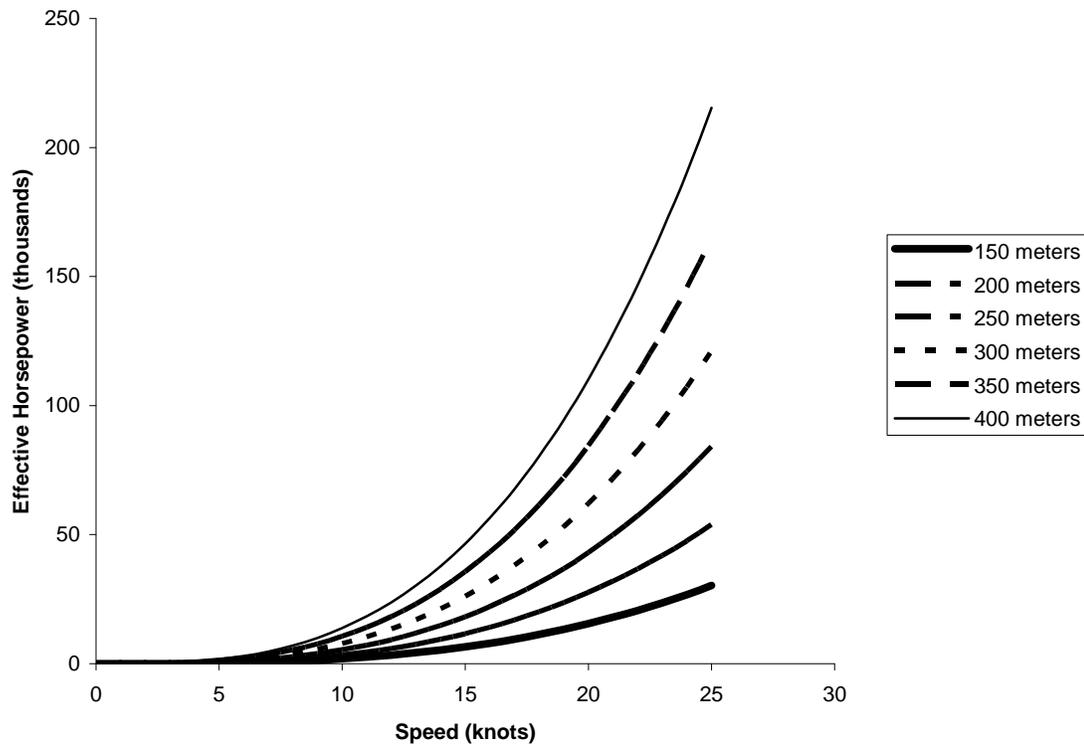


It is seen from figure 3 that, for most land vehicles, the available power exceeds what is needed to maintain the vehicles at a particular speed. For example, the average speed for private automobiles is estimated to be about 45 mph. To maintain that cruising speed, the Honda Accord, as shown in figure 3, requires about 6% of its rated horsepower. At its maximum allowed speed, the Abrams tank, in cruising mode, would require about half of its rated horsepower. The MRAP has a maximum rated speed of 69 mph. At that speed it would be operating at its maximum horsepower. In general, the horsepower of a land vehicle is determined by the acceleration requirements rather than the requirement to maintain a particular speed.

The simplified model described in appendix A can also be used to provide estimates regarding the power and energy requirements of displacement-type seagoing vessels. In that case, the rolling force and the gravity force will be taken as zero. This leaves the inertial force and the drag force as the factors that determine power and energy requirements. The density of water is about one thousand times that of air, and the relevant area in the drag force is the ship wetted area. A simplified model for the wetted area and the drag force for displacement hull surface ships is presented in appendix A.

For purpose of illustration, figure 4 provides estimates of the horsepower needed to maintain tanker class ships with lengths between 150 and 400 meters, at a particular speed. A drag coefficient of .004 was taken as being representative of the tanker ships (see Lin et al<sup>3</sup>).

Figure 4. Cargo ship required effective horsepower vs cruise speed in knots (150-400 meter length)



As a point of comparison, the VLCC tanker *Frank A Shrontz*, with a length of about 330 meters and a cruising speed of 16 knots, has a power plant of about 34,000 horsepower. This is in reasonable agreement with the predicted value obtained from figure 4 and suggests that the power plants chosen for cargo ships are selected to be close to the power needed to maintain a desired cruising speed. Similar calculation can be done for fast ships (war ships, cruise ships) when the appropriate values of the drag coefficient and wetted surface areas are known. It is clear that ships involved in modern commerce, as well as upper end military vessels and cruise ships, have large power requirements. Since these vessels must travel long distances, fuel efficiency can be expected to be a significant factor in engine selection. The following sections will discuss, among other things, factors that influence fuel efficiency.

### 3. Review of Engine Technologies

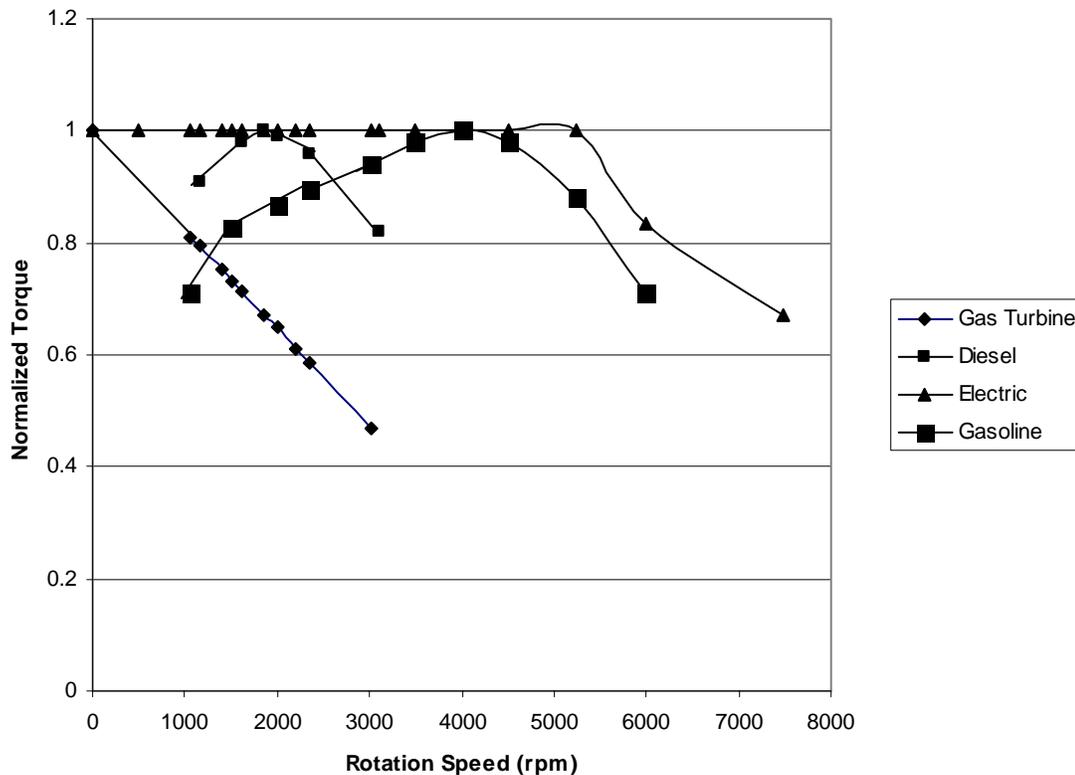
The discussion so far has been focused on mission requirements and has been largely independent of the selection of power plants or fuels. Once mission requirements have been determined, then the selection of the engine most appropriate to the mission can be undertaken. While there are a large number of engine technologies available, most engines of interest to transportation fall into the categories of internal combustion (e.g., gasoline engines, diesel engines, and gas turbines), steam turbines, electric motors, and combinations of the above. This section will undertake a brief review of several of these engine technologies and the means used to select among them.

The internal combustion engines and the steam turbines operate by creating a hot gas or vapor and subjecting that gas or vapor to a thermal cycle that converts heat energy into mechanical energy. This conversion may be accomplished by pushing pistons or rotating turbine blades. As a result, the efficiencies of the conversion processes are limited by the laws of thermodynamics. This efficiency is called the thermal efficiency and depends on the thermal cycle that characterizes each engine. The principal thermal cycles used are the Otto Cycle (gasoline engines), the Diesel Cycle, and the Brayton Cycle (gas and steam turbines). These cycles are usually described in terms of a closed curve on a pressure-volume chart. The Otto cycle, for example, involves a closed curve that connects two volumes (e.g., the piston down volume and the piston up volume). Energy is required to compress the fuel air mixture as one goes from the piston down state to the piston up state. A spark is used to ignite the fuel air mixture. This releases chemical energy in the form of heat, which raises the pressure in the compressed gas, thereby creating mechanical energy by pushing the piston so that it travels back to its down state. This mechanical energy is transferred to a flywheel that is used to provide torque to power the wheels and energy to recompress the gas. Heat that is left in the gas after the down stroke is removed, the cylinder is recharged and the cycle is repeated. The thermal efficiency of this process is just the energy supplied by combustion minus the heat that is removed when the cylinder returns to the down state divided by the energy that was supplied by combustion. This efficiency is found to be a function of the ratio of the uncompressed volume to the compressed volume and increases as this ratio increases. Because of the properties of gasoline, the permitted ratio is usually less than 10:1, and the ideal thermal efficiency is about 47%. No thermal cycle is ideal. The non-ideal factors reduce the Otto cycle thermal efficiency to about 37%. The Diesel cycle is slightly more complicated than the Otto cycle in that it operates between a constant volume and a constant pressure. Its thermal efficiency, however, also involves a volume compression ratio, which, because of the nature of the diesel compression and of diesel fuel, can be much greater than the Otto cycle compression ratio. Compression ratios of 20:1 can be achieved. This leads to diesel engines usually being about 30% more efficient than gasoline engines. The ideal Brayton cycle operates between two pressures, and its thermal efficiency can be shown to be determined by the pressure ratio. Pressure ratios up to 40:1 have been used and can lead to ideal thermal efficiencies of about 60%. Those interested in the details of these thermal cycles will easily find descriptions via an Internet search.

While the thermal efficiencies are important, from a mission viewpoint, the principal propulsion plant parameters of interest are torque, thrust, power, fuel consumption, weight, and volume. We will briefly review these for the engines mentioned above.

If we consider the case where the output power is extracted from a rotating shaft, then of particular interest is torque  $T$ , which is the amount of force applied tangentially to a circle, so that the load at a particular rpm is measured by the torque being applied by the vehicle driveshaft. Torque is routinely measured as part of characterizing a particular engine. The torque characteristics differ among the various types of engines typically used in transportation and influence the decision regarding what type of engine to use in a particular application. In order to illustrate the torque differences among engine technologies, Figure 5 compares the torque vs. rotation rate for several engine technologies applied to engines of similar size (in each case with the engine set for maximum power and the curve derived from a commercially available engine). For each engine technology, the torque has been normalized to a maximum value of one in order to cleanly display the various torque characteristics on a single chart.

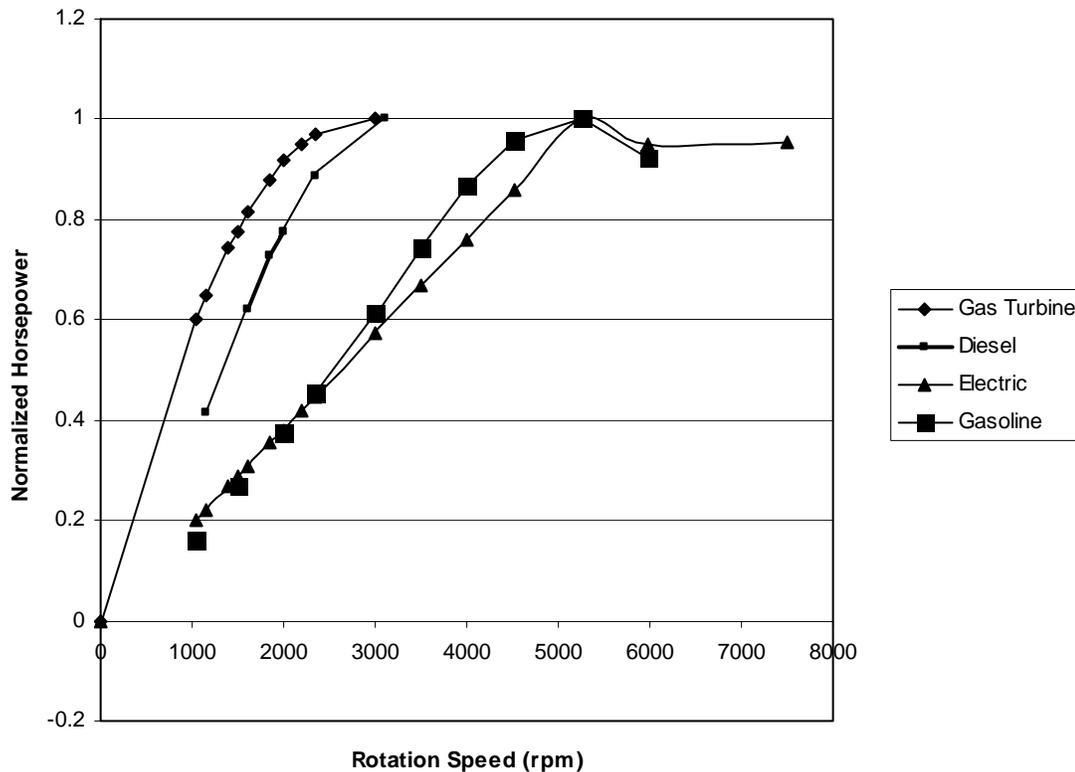
Figure 5. Normalized torque vs rotation speed



It is evident from figure 5 that the various engines have quite different torque characteristics. The electric motor has close to ideal torque characteristics in that its torque is independent of rotation rate until it reaches high rpm. This makes this engine, in principle, broadly applicable. However, as we shall see later, there are significant challenges in providing the power and energy needed to broadly apply this engine to

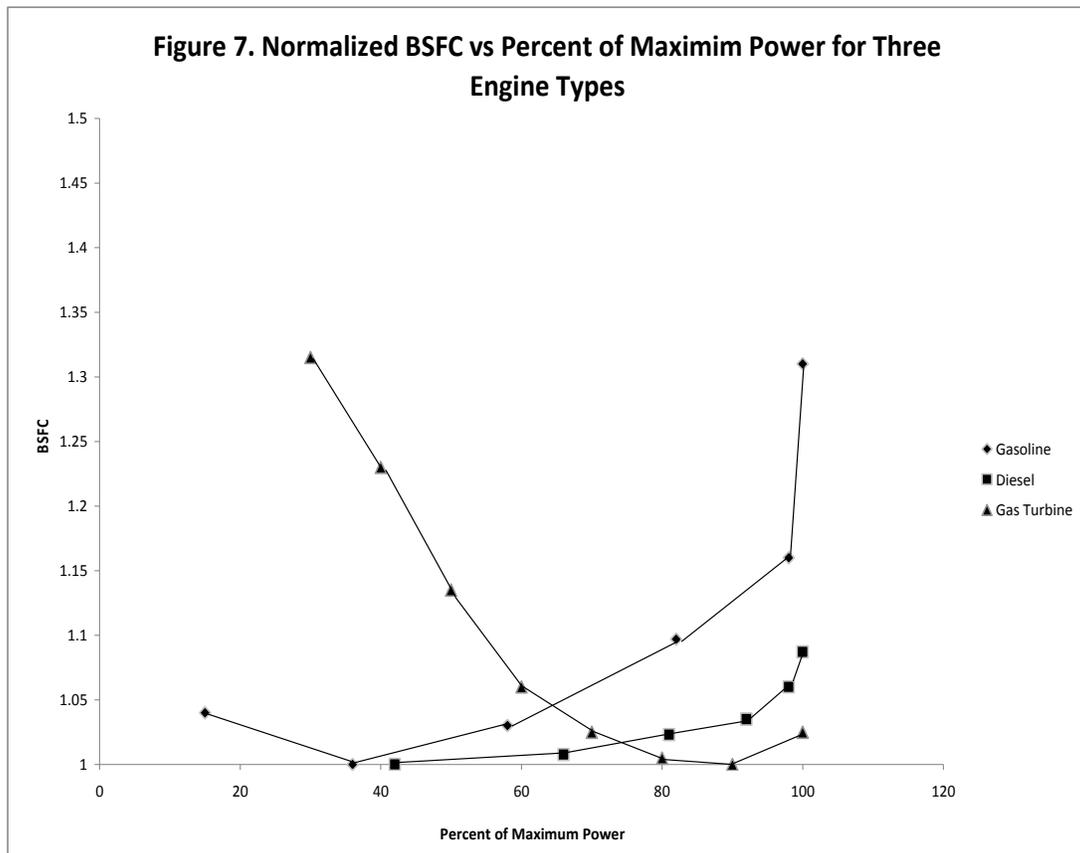
many transportation applications. The gas turbine engine achieves maximum torque at low rpm with the torque declining as the rpm increases. High torque at low speed is needed for rapid acceleration and for moving large loads. However, for this engine, the maximum torque at low shaft rotation rate is only achievable with the compressor operating at maximum and the output shaft strongly braked. This results in significant fuel consumption at low speeds thereby limiting its application in the low rotation rate arena. In the case shown, the diesel engine provides maximum torque at about 1800 rpm. This torque peak occurs at substantially lower rpm than does the peak for a similar size gasoline engine. This is one of the reasons why diesel engines are used for hauling freight and gasoline engines are not. The gasoline engine curve is broad and provides maximum torque at about 4500 rpm for the case shown. This allows the application of high torque at high speed, which is desirable for passenger cars.

Figure 6. Normalized Horsepower vs Rotation Speed



While torque is the parameter that determines the force (and hence the acceleration) that a rotating shaft can apply, the power provided by the shaft determines the rate of fuel consumption needed to accelerate a vehicle and keep it in motion. The power  $P$  provided by a rotating shaft is related to the torque by the expression:  $P = T \times 2\pi \times f$ , where  $f$  is the rotation rate of the shaft. Thus, the power is directly obtained from a measurement of the torque. Figure 6 provides the horsepower curves that result from the torque curves shown in figure 5. The power curves have been normalized such that the maximum horsepower for each engine is one.

It can be seen from figure 6 that the horsepower curves for the gas turbine and for the diesel are similar, although the gas turbine develops its horsepower more rapidly at low rotation rates. The similarity occurs because the engines used as the basis for the curves were designed for similar applications, namely that of powering light trucks and buses. The curves for the electric engine and the gasoline engine are also similar, because the engines that formed the basis for these curves were designed to power passenger cars. Figures 5 and 6 make the obvious point that the mission of the vehicle strongly influences the selection and design of the propulsion power plant.



A third factor that is important in characterizing an engine is its fuel consumption. The energy flow into an engine can be easily determined by measuring the rate at which fuel is consumed. If the fuel is liquid, then the rate of consumption might be measured in grams per second. If it is a gas, then the rate of fuel consumption might be measured in cubic meters per second. If the energy supply is electric, then the supply current and the supply voltage would be measured to give the energy input rate directly in Watts. In the case of internal combustion engines, the chemical energy content of the fuel is released upon combustion. For example, gasoline has a chemical energy content of about 43 MJ/kg, while natural gas has energy content at normal temperature and pressure of about 38 MJ/m<sup>3</sup>. Thus, if one measures the consumption of gasoline in kg/s, or that of natural gas in m<sup>3</sup>/s, then it is straightforward to obtain the energy consumption rate in MJ/s. The energy consumption is, of course, specific to the load that has been applied to the engine and the rate at which the engine is turning. These can be directly measured. The results of

these measurements are usually expressed as the ratio of the rate of fuel consumption in grams per second to the power in Watts (Joules per second) being produced by the engine. This ratio is referred to as the brake specific fuel consumption (BSFC) and is often expressed in grams per kilowatt hour. Figure 7 plots the normalized BSFC versus the percent of maximum power for the three road vehicle internal combustion engines considered above.

The BSFC in figure 7 is normalized to the minimum BSFC for each engine (with the engines set for maximum power). BSFC of unity, or the point where each curve touches the power axis, is the power at which minimum fuel consumption occurs. The gasoline and diesel engines show a BSFC minimum in the vicinity of 40% of maximum power. The gas turbine engine shows a minimum at 90% of maximum power. From a fuel consumption viewpoint, it is clear that these engines are best suited for different applications. The gas turbine shows high fuel consumption at low power and is best suited for applications where it will operate near maximum power most of the time or where high torque (or thrust) at low speed is a requirement that overrides high fuel consumption. The gasoline engine shows high fuel consumption when operated near maximum power and is best suited to applications where maximum power is required during only a small fraction of its operation. The diesel engine demonstrates relatively flat BSFC over much of its power range but the BSFC does increase rapidly as it nears maximum power. While it is possible to modify the BSFC curves by various engine modifications, the basic trends shown in figure 7 are intrinsic to the engine types.

When two power plants can meet the mission torque, power, and fuel consumption requirements, then other factors, such as engine size and weight, will determine which engine is selected. This leads to the introduction of engine characteristics such as specific weight (lb/h.p.) and specific volume (cu.ft./h.p.). Table 3 provides a comparison of several engines including these additional characteristics.

It is clear from table 3 that there is considerable variability among the various engines. For example, among the internal combustion engines, the marine diesel represents the heaviest technology and requires the largest installation volume. On the other hand, it has among the lowest specific fuel consumption and the highest energy efficiency. Hence, this technology finds its applications to missions where weight and volume are not a constraint, but fuel efficiency is of great concern. As a result, the marine diesel currently dominates in the area of commercial ship propulsion. At the other extreme is the gas turbine. This is the lightest technology and requires the least volume. However, it has rather high specific fuel consumption and modest energy efficiency. This technology finds applications where weight and volume are constrained and high power is desired but where fuel efficiency is not a major constraint, or where the engine is expected to operate at maximum power most of the time. This technology is used in military platforms such as tanks and ships and, of course, dominates the field of aircraft propulsion, where several variations of the technology (e.g., turbo shaft, low bypass turbo fans, turbo jets) are employed depending on the aircraft mission.

Engine	Specific Weight lb/h.p.	Specific Volume cu.ft./h.p.	Minimum Specific Fuel Consumption lb/h.p.hr.	Engine Energy Efficiency
Low-rpm Marine Diesel 109,000 h.p.	42	0.35	0.26	0.54
Diesel 160 h.p.	7	0.3	0.22	0.35
Gasoline 180 h.p.	2.5	0.05	0.45	0.25
Gas Turbine 1500 h.p.	1.7	0.03	0.45	0.4
Gas Turbine 57,330 h.p.	0.3	0.03	0.33	0.42
Electric 288 h.p.	.25	0.02	NA	0.9

**Table 3.** Specific weight, specific volume, specific fuel consumption, and energy efficiency for several engines.

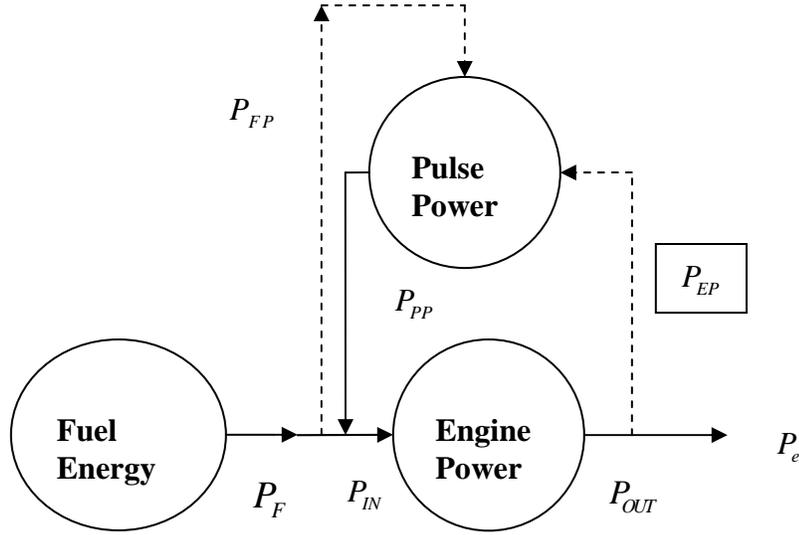
The electric motor stands out among the several technologies listed in table 3. It is the lightest technology, requires the least volume and has the highest energy efficiency. All things being equal, this would seem to be the best technology for delivering shaft horsepower. However, it will become clear in the following section that the application of electric motors to transportation propulsion is quite challenging. If the challenges can be overcome, the electric motor could have a very large impact on the choice of alternative transportation fuels.

## 4. Selecting the Power Plant

Section 2 provided a brief overview of how mission requirements translate into dynamical and kinematical requirements. Section 3 provided a brief review of engine technologies that might be compatible with those requirements: diesel, gasoline, gas turbine, and electric. This section will provide a brief review of how to evaluate various power plants within the context of specified missions, and also includes an overview of the current status of batteries and fuel cells in the discussion of the electric motor engine.

Engines must be supplied with fuel (energy) if they are to do anything. Figure 8 provides a simple conceptual drawing of how power might flow in a propulsion power plant.

The “engine power” circle represents the components that provide the power to generate the force that propels the vehicle. The engine power usually conveys via a rotating shaft that generates torque to drive wheels, treads, or propellers or through an exhaust fluid that provides thrust as in a jet engine. The “fuel energy” circle represents the component that provides the primary energy to power the engine. This could be a tank of fuel (e.g., gasoline, diesel, ethanol, and methanol), a pack of batteries, or a fuel cell and its fuel. The primary power supply may not be able to generate the peak power required by the vehicle’s mission even though it must be able to provide the average required power. In these cases it is necessary to incorporate a power source that can provide the required peak power. This power source is designated by the “pulse power” circle. The pulse power source may be a battery or may be composed of devices such as electrical capacitors. The intent of the pulse power unit is to provide high power for short times such as when acceleration is needed to climb a hill. The pulse power source will need to be charged or recharged from either the primary fuel or from output power of the engine as indicated by the dashed lines in figure 8. While the figure shows only one engine, it may involve several engines, such as occurs with the combination of internal combustion and electric engines in hybrid drive vehicles. The quantity  $P_F$  is the primary power delivered by the fuel. For example, if the engine were an internal combustion engine then  $P_F$  would be the energy content per kilogram of fuel times the number of kilograms per second of fuel being supplied to the engine. If the engine were an electric motor, then  $P_F$  would be the voltage times the current being supplied by the batteries, electric generator, or fuel cells. The quantity  $P_{FP}$  is the primary fuel power that is diverted to charge the (auxiliary) pulse power system. The quantity  $P_{IN}$  is the input power to the engine, while  $P_{OUT}$  is the output power of the engine. These quantities are related by the efficiency of the engine. The quantity  $P_{EP}$  represents engine output that is diverted to charge the pulse power system and  $P_{PP}$  is the delivered pulse power. The quantity  $Pe$  is the power that is actually provided to propel the vehicle and is determined by mission requirements. The mass appropriate to the power plant is the sum of the engine mass  $M_e$  and the fuel mass  $M_f$ , where  $M_f$  includes the fuel and the pulse power masses.



**Figure 8.** Conceptual outline of power flow within a vehicle power plant.

The energy  $E_s$  that can be extracted from the various energy sources is mostly well understood. This energy is supplied to an engine that can turn it into useful work with an efficiency  $\eta$ . It is obvious that the energy  $E_s$  is a function of the mission duration and the mission effective power requirements  $P_e$ . The fuel mass  $M_f$  is often related to the source energy  $E_s$  by the expression  $E_s = M_f e_s$ , where  $e_s$  is the specific energy of the fuel. For example, for gasoline  $e_s = 12$  Watt hours per gram (Wh/g) of gasoline. This allows the determination of the fuel mass needed to provide the mission energy  $E_s$ . The fuel mass is taken to be the sum of the masses of all the components (i.e., fuel, batteries, fuel cell, generator, pulse power) that supply energy to the engine. The energy and power that can be extracted from fuels, batteries, fuel cells, pulse power systems, and generators are determined by detailed measurements that characterize particular fuels, batteries, fuel cells, pulse power systems and generators. These detailed measurements allow one to characterize various power plants in terms of their specific power and specific energy. For a given mission, the specific power  $SP$  of the total power plant is defined as

$$SP = \frac{P_e}{M_f + M_e}. \quad (1)$$

Similarly, the specific energy  $SE$  of the total power plant is defined as

$$SE = \frac{\eta E_s}{M_f + M_e}. \quad (2)$$

These quantities are mission dependent. We saw in section 2 that  $P_e$  is determined by acceleration and/or speed requirements and by the total mass of the vehicle. For the purpose of discussion, we will assume that the mass of the vehicle is much greater than the sum of the fuel mass and the engine mass. In this case,  $P_e$  becomes independent of  $M_f$  and  $M_e$ . As a result,  $SP$  will decrease as  $M_f$  increases (i.e., as the mission duration increases). The source energy  $E_s$  is taken to be proportional to the fuel mass  $M_f$ . Thus, for very long missions, when the fuel mass is much greater than the engine mass, the power plant specific energy will become constant and equal to the specific energy of the fuel source times the conversion efficiency of the engine. The conversion efficiency is a function of the power being supplied to the engine. At the other extreme, when  $M_f$  is much less than  $M_e$ , the power plant specific energy will scale as  $M_f/M_e$ .

Power has units of energy divided by time. Thus, the ratio  $SE/SP$  defines a time  $t$  where

$$t = \frac{\eta E_s}{P_e}. \quad (3)$$

The time  $t$  provides an estimate of the time to deplete the fuel supply and, hence, of the time between refueling or recharging.

Ordinarily, the mission requirements will determine  $P_e$ ,  $M_f + M_e$  and  $t$ . Once these are specified, then  $SP$  and  $SE$  become determined for the mission. Since only  $M_f + M_e$  is specified, there is a tradeoff between  $M_f$  and  $M_e$ . As an illustration of the outcome of such a specification/tradeoff, table 4 provides estimates of  $SP$ ,  $SE$  for several commercial engines that have been chosen to respond to the specifications indicated. The specifications have been selected to cover the range from passenger cars to massive cargo ships.

The specific powers shown in table 4 are calculated for maximum power. Hence, the discharge times shown are for maximum power. As the power level is decreased below maximum power the discharge time will increase accordingly. For example, the Honda J30 engine operating at 10% of maximum power would have a discharge time of about 8 hours with the fuel mass indicated.

The data shown in table 4 provide some insight into the various power plants. For example, the large, low-rpm diesel RTA96-C is clearly designed for specific energy rather than for specific power. Even if the fuel mass of this power plant were reduced to being much less than the engine mass, the maximum specific power would be only about 40 W/kg. This power plant is designed to economically move large masses long distances. The power plants associated with the two gas turbines (LM6000 and AGT-1500) represent a compromise to provide reasonably high specific power and specific

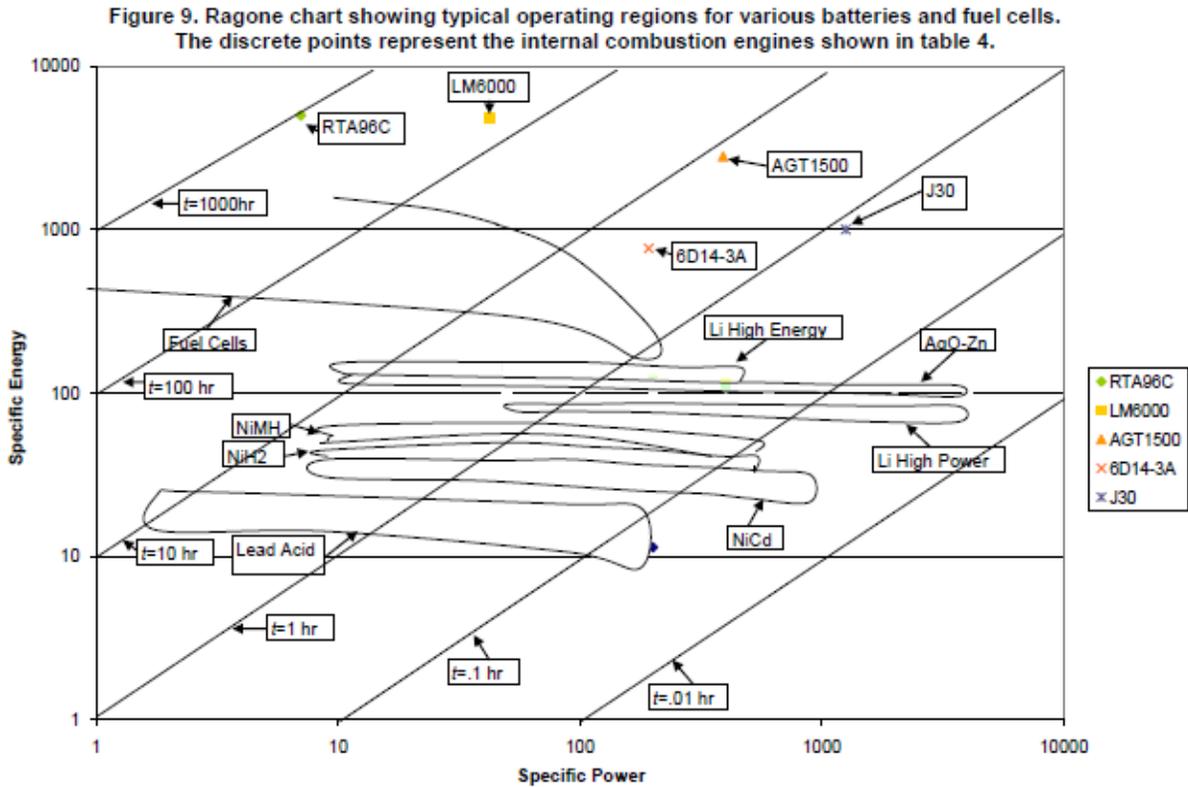
energy as required by their military applications. The diesel plant 6D14-3A has been designed to provide moderate specific power and relatively high specific energy. The gasoline plant J30 has been designed to provide both high specific power and high specific energy. The battery electric power plant has opted for a relatively high specific power in order to compete for the passenger vehicle mission. The low specific energy of the power plant is a result of the low specific energy of the battery technology employed in the power plant and reflects the current state of battery technology.

Engine selected	Specified Max Horse-power	Specified Engine Mass + Fuel Mass	Specified Depletion Time (hours) @Max HP	Resulting Engine Mass (kg)	Resulting Fuel Mass (kg)	Efficiency of Selected Engine	Specific Power (W/kg) @ Max HP	Specific Energy (Wh/kg)
Wartsila-Sulzer RTA96-C Diesel (ship)	109,000	$1.2 \times 10^7$	735	$2 \times 10^6$	$10^7$	.5	6.8	5,000
General Electric LM6000 gas turbine (ship)	57,330	$10^6$	113	7,818	$10^6$	.4	42.5	4,800
Honeywell AGT-1500 gas turbine (tank)	1,500	2,800	7	1134	1666	.4	390	2,800
Mitsubishi 6D14-3A Diesel (bus/truck)	160	620	4	500	120	.33	192	767
Honda J30 Gasoline (automobile)	245	146	.8	110	36	.25	1,253	1,000
Tesla battery (electric car)	288	483	.2	33	450	.9	445	99

**Table 4.** Specific power, specific energy, and depletion or discharge time for several engines with typical mission assignments indicated in parenthesis.

Data of the type shown in table 4 provide a straightforward means for making rough comparisons among power plant technologies as they apply to particular missions. In section 3, it was shown that an electric motor has the most attractive torque, efficiency, and weight characteristics of the shaft horsepower systems considered. Let us now consider the application of electric engine technology to transportation power plants that

must carry their own energy. Ragone introduced a chart that plots specific power against specific energy.<sup>4</sup> The chart is now widely used to compare power technologies. Figure 9 provides a “Ragone chart” that summarizes the state of the art for several battery and fuel cell technologies.



Sources: Scott, [http://ntrs.nasa.gov/archive/nasa/casi.ntrs.nasa.gov/20070021785\\_2007019841.pdf](http://ntrs.nasa.gov/archive/nasa/casi.ntrs.nasa.gov/20070021785_2007019841.pdf). *Meeting the Energy Needs of Future Warriors*, The National Academies Press, 2004 available at <http://www.nap.edu/openbook.php?isbn=0309092612&page=40>.

The diagonal lines in figure 9 represent depletion times ranging from 0.01 hours to 1000 hours. The depletion times are indicated for each line. As discussed above, the mission of a vehicle would determine its mass, its required peak power, its average power, the depletion time at peak power, and the mass and volume that can be allocated to the power plant. The ratio of the required peak power to the available power plant mass determines the peak specific power. The intersection of the required peak specific power and the depletion time line determines the required specific energy. This information allows one to obtain a sense of what power plant technologies are available to meet the mission requirements.

The discrete data points on the plot represent the data from table 4 and are evaluated at the mission maximum power requirement. For instance, the J30 Honda gasoline combustion engine can operate at full power for about 1 hour. The internal combustion plant discrete data points shown in figure 9 are representative of DOD requirements for light passenger vehicles, light trucks, land moving equipment, tanks, ships, and aircraft. It

is noteworthy that all of these data points lie outside the regions that are directly accessible by currently available battery and fuel cell technologies. There are batteries that have the required specific power but not the required specific energy. The fuel cells may meet the specific energy requirements for average power for the J30 and 6D14-34 power plants but not the specific power requirements at maximum power. It is necessary that both requirements are met because they are set by the mission. However, it is not always necessary that these two requirements be met simultaneously. For example, most of the time, the 6D14-3A diesel engine shown in figure 9 may operate at a point on the 10-hour depletion that lies just inside the region covered by fuel cells. As long as the fuel cell can provide the additional energy needed to recharge the batteries (or capacitors) and also provide the energy needed to meet the average power needs, a hybrid solution that combines technology that can produce high power for a short time with technologies that can produce low power for long times might be possible. However, as the average power becomes closer to the peak power this becomes difficult to do. This is the situation for the data points represented by the AGT 1500, the LM6000, and RTA96-C power plants. It seems unlikely that any future battery and fuel cell arrangement will meet the requirements represented by those points. It is, of course, possible to provide an electric drive solution to those requirements by connecting (with appropriate reduction gears) the driveshafts of those internal combustion power plants to a properly sized electric generator, and then provide the generated electric power to an electric motor for electric drive. This would increase the mass and volume associated with the power plants and would slightly reduce the conversion efficiency, but should not greatly shift the location of the associated points in figure 9. For the large systems involved here, the efficiency loss could be compensated for by employing co-power generation, where the waste heat from the internal combustion process is captured to raise steam for the purpose of generating additional electric power. This, of course, further increases the mass and volume required for the total power plant. However, cogeneration is widely used and can achieve overall efficiencies of 60%. This approach can be quite attractive if the mass and volume allocation for the power plant can accommodate it. Such an electric power solution is actually an internal combustion solution rather than an all-electric solution. The major reason to consider such an approach would be the potential convenience and flexibility that a large electric power plant might provide (e.g., ship propulsion power and ship onboard power from a common power source).

For shaft horsepower applications, the electric motor is the most attractive in terms of principal propulsion plant parameters, as we saw in section 3. However, the Ragone chart figure 9 shows that the electric motor is currently limited by the specific energy and specific power characteristics of available battery and fuel cell systems. There are ongoing battery developments that could improve the viability of electric motors for transportation. One example of this is the lithium air battery.<sup>5</sup> This battery chemistry is currently under study, and Ragone charts are not yet available. Based on the theoretical maximum energy density of the lithium air chemistry and the industrial experience that relates theoretical energy density to energy density that can be achieved in practice, expectations are that a primary lithium air cell could achieve an energy density of 1700 Wh/kg. If this energy density could be achieved in a rechargeable lithium-air cell, and if the discharge characteristics allow a specific power in the 1000 W/kg range, then this hypothetical lithium-air cell would approach the range now occupied by internal

combustion engines. In order to gain some insight regarding how this hypothetical battery would impact the matter of transportation fuels, it is interesting to compare the depletion times shown in table 4 with those that would be predicted when the sum of the engine mass and the fuel mass is that shown in table 4 but the power plant is composed of an electric motor and the hypothetical lithium air battery that has an energy density of 1700 Wh/kg and is able to meet the specific power requirements shown in table 4. This comparison is done in table 5.

Engine	Measured Depletion Time (hrs) for Several Engines, from Table 4	Hypothetical Depletion Time (hrs) Using Hypothetical Li-Air Battery and Electric Motor
Tesla (electric)	0.2	3.15
J30A (gasoline)	0.8	0.95
6D14-3A (diesel, land)	4	7
AGT1500 (gas turbine, land)	7	3
LM 6000 (gas turbine, ship)	113	21
RTA96-C (diesel, ship)	735	211

**Table 5.** Comparison of depletion times from table 4 with those predicted for a replacement of the power plant with a hypothetical Li-Air battery and an electric motor.

In this table, the Tesla electric motor is used for both the replacement of the Tesla power plant and the J30A power plant. The 6D14-3A and AGT1500 engines are replaced by industrial quality electric motors that have specific weights of one pound per horsepower. The LM 6000 and RTA96-C engines are replaced by electric motors that have specific weights of 15 pounds per horsepower, which is representative of similar sized electric motors used to power the RMS Queen Elizabeth II.<sup>6</sup>

The hypothetical Li-Air battery considerably increases the depletion time for the Tesla power plant. The J30A replacement plant provides a slightly increased depletion time. Since both the Tesla and J30A power plants are expected to spend most of their operating time at about 10% of maximum power, it seems likely that a day’s driving (about 400 miles) could be accomplished with the hypothetical Li-Air battery power plant. This would make overnight recharging of the batteries reasonable at about a 10 KW charging rate. The 6D14-3A power plant replacement provides about a 70% increase in the depletion time resulting in a 7-hour depletion time at maximum power. If one assumes that the application of this power plant will require that it operate on average at half its maximum power, then the time between recharging would be about 14 hours. A 10-hour recharge time would require a 100 KW charging system. This arrangement might be viable for commercial applications (bus, light truck, etc) where recharge periods could be scheduled. However, it is unlikely to be suitable for military applications where vehicles must be available on demand and recharge time requirements are measured in minutes. In the cases of the use of Li-Air batteries and electric motors to replace the AGT 1500,

LM6000 and RTA96-C power plants, the replacement power plant depletion times do not meet the mission requirements.

From the above discussion one can conclude that, if the hypothetical, rechargeable Li-Air battery (SP = 1000 W/kg, SE = 1700 Wh/kg) were realized and found to be economical, durable and safe enough for manned vehicular use, it would enable the replacement of the internal combustion-powered passenger vehicle with an all electric vehicle that could travel 400–500 miles on a single charge. It is interesting to speculate on how such a development would impact the matter of transportation fuels. Table 1 lists the 2007 U.S. usage of petroleum and indicates that about 13.4 million barrels per day is used for transportation purposes. About 70% of this usage can be attributed to passenger vehicles, which appear to be amenable to being powered by the hypothetical Li-Air battery. Thus, if the hypothetical, rechargeable Li-Air battery were realized and found to be economical, durable, and safe, 70% of the need for conventional transportation fuel could be eliminated. This outcome would have a very large impact on alternative transportation fuels. The burden of fueling vehicles now powered by gasoline would pass to the nation's electric grid. Since passenger vehicles travel about five billion miles per day, the burden on the grid would be about  $10^{11}$  Watts corresponding to about 20% of current average electric power consumption of  $5 \times 10^{11}$  Watts. The total U.S. electric generating capacity is about  $10^{12}$  Watts. Thus, it may be possible that this increase could be absorbed by the existing generating capacity, in which case there would be no power plant construction required to transition passenger vehicles to electric drive on a large scale. However, because peak electric power requirements can be about 80% of the maximum generating capacity, it would be prudent to plan on adding the additional capacity needed to accommodate a large-scale move to electric passenger vehicles.

The technology options for provision of this additional electrical capacity are likely to be broader than those associated with the production of a hydrocarbon or alcohol replacement of gasoline. For example, the additional capacity could be provided by doubling the Nation's current nuclear power electrical generating capacity or adding additional coal or natural gas electrical power plants.. There is a great deal of uncertainty regarding the capital cost associated with constructing new nuclear power plants. A unit cost of about \$1500/KW<sub>e</sub> is at the lower end of estimates that are now appearing in the literature. This unit price is also representative of coal-fired power plants. At this unit price, the capital cost of adding  $10^{11}$  W would be about 150 billion dollars. There would, of course, be additional capital investments needed to put in place the infrastructure that would produce and recycle the batteries and the infrastructure associated with recharging the electric vehicles. The total capital investment, however, is likely to be comparable or less than that associated with putting in place a synthetic fuel production infrastructure required to replace petroleum-derived gasoline. In light of this, it would seem that a resolution of the viability to transportation systems of Li-Air-like battery chemistries will be important to determining the future direction for alternative transportation fuel initiatives.

Central questions are: can Li-Air battery technology provide needed acceleration, and, is it viable for heavy vehicles? At this time it is not clear that the Li-Air chemistries will be viable for transportation systems. For example, the high specific energies that have been reported for Li-Air batteries involve low discharge currents, where the discharge

times are measured in hundreds of hours. While the published data is limited, it is clear that the energy that can be extracted from the batteries decreases rapidly with increasing discharge currents, which would be necessary for rapid vehicular acceleration. This is the same phenomenon that is evident for batteries and fuel cells in the Ragone chart given in figure 9. It is possible and even likely that the Li-Air battery will prove to be a high specific energy device but a low-to-moderate specific power device. Furthermore, even if the chemistries do enable large-scale use for passenger vehicles, it is unlikely that they will enable battery-powered heavy trucks, jet aircraft, armored vehicles, tanks, and large ships.

Missions drive the need for heavy trucks and armored vehicles, and the consequent need for combustion engines—and hence the need for liquid fuels that have the attractive features of petroleum-based fuel products. It is, therefore, prudent to continue to investigate alternative means to the equivalent of conventional fuels, especially those that are not likely to be supplanted by all-electric propulsion. The following sections will provide an overview of several approaches in this regard. We start with hydrogen, followed by coal to liquid, natural gas and gas hydrate-derived fuels, bio-derived fuels, CO<sub>2</sub>-derived fuels and, finally, oil shale.

## 5. The Role of Hydrogen

This section will provide a brief discussion of the role of hydrogen in alternative transportation fuels. Hydrogen is broadly important to the subject of alternative transportation fuels, so is considered first in this review. It may be a constituent of the fuel (e.g., hydrocarbons or alcohols), it may play a role in battery chemistry or fuel cell chemistry, or it may be the fuel itself (e.g., a hydrogen-fueled internal combustion engine). The prospects for hydrogen as a fuel for DOD were discussed by Coffey et al.<sup>7</sup> This section will summarize the relevant findings from that paper.

To begin that discussion it is helpful to put hydrogen into perspective relative to several other fuels. It is clear from eq. (A1) that the fuel mass that a vehicle must carry directly impacts on the vehicle dynamics. Also, the volume constraints on transportation vehicles place significant limits on the amount of fuel that a vehicle can carry. Thus, as discussed earlier, energy per unit mass and energy per unit volume are important metrics for judging the viability of various transportation fuels. Since the most familiar transportation fuel is gasoline, it is helpful to have an understanding of energy content of various alternative energy sources of interest relative to the energy content of gasoline. This is provided in table 6 for several energy sources. If one wishes to estimate real energy densities rather than relative energy densities, one can take the specific energy of gasoline to be about 12,000 Wh/kg, or about 9 Wh/cc. Multiplication of columns two and three of table 6 by the appropriate specific energy of gasoline will provide estimates of the specific energies of the various energy sources listed.

It should be clear from table 6 why the liquid hydrocarbon fuels (particularly gasoline and diesel) have been dominant for the past 100 years. With the exception of hydrogen, they provide the highest energy content by either measure and are easily stored at room temperature and pressure. Were it not for growing concerns regarding their continued easy availability and their potential adverse environmental impact, hydrocarbon fuels would remain the obvious transportation fuels of choice. The liquid alcohol fuels ethanol and methanol have the next highest energy content by either measure (again, except for hydrogen). The hydrocarbon gas methane, when pressurized to 10,000 psi, approaches its liquid energy densities and approaches 50% of the volumetric energy density of gasoline. The listed batteries have the lowest energy content by either measure (except for hydrogen @ 3000 psi) of any of the fuels listed.

Regarding hydrogen, it can be seen from table 6 that hydrogen has the highest energy content per unit mass of any of the listed fuels. However, for transportation fuels, energy content per unit volume is often the more important parameter because of volume constraints. By this metric (with the exception of batteries), hydrogen has the lowest energy content of the listed fuels. Furthermore, to obtain hydrogen's highest volumetric energy content it must be cooled to  $-253\text{ C}^\circ$  or pressurized to over 10,000 PSI. These properties of hydrogen make it problematic as a fuel, especially for most high-performance DOD platforms.

Energy Source	Energy per unit mass	Energy per unit volume	Temperature ° C	Chemical Formula
Liquid Gasoline	1.0	1.0	25	<C <sub>8</sub> H <sub>18</sub> >
Liquid Diesel	.97	1.1	25	<C <sub>12</sub> H <sub>23</sub> >
Liquid propane (@ 90psi)	1.0	.86	25	C <sub>3</sub> H <sub>8</sub>
Liquid Methane	1.3	.75	-162	CH <sub>4</sub>
Liquid Ethanol	.61	.69	25	C <sub>2</sub> H <sub>5</sub> OH
Liquid Methanol	.44	.51	25	CH <sub>3</sub> OH
Liquid hydrogen	2.6	.27	- 253	H <sub>2</sub>
Methane Gas (@ 3000 psi)	1.3	.37	25	CH <sub>4</sub>
Methane Gas (@ 10,000 psi)	1.3	.5	25	CH <sub>4</sub>
Hydrogen Gas (@ 3000 psi)	2.6	.06	25	H <sub>2</sub>
Hydrogen Gas (@ 10,000 psi)	2.6	.2	25	H <sub>2</sub>
Lead Acid Battery	.003	.006	25	NA
Li Ion Battery	.013	.026	25	NA
Li Polymer Battery	.01	.029	25	NA
Hypothetical Li-Air battery	.14	.1	25	NA
NiMH Battery	.004	.02	25	NA

**Table 6.** Energy content and chemical composition of several energy sources referenced to gasoline. The bracket < > indicates the average chemical formula. (Source: modified from Coffey et al.<sup>7</sup>)

Hydrogen is the simplest element and can be considered to exist in unlimited supply on earth. When combined with oxygen in a fuel cell it produces electricity (and water) that can be used to power vehicles. The range of specific energy and specific power of typical fuel cells is summarized in figure 9. If pure hydrogen is stored on the vehicle, a fuel cell can convert it to electricity with about 80% efficiency. This is conceptually a straightforward approach and eliminates CO<sub>2</sub> production on the vehicle, but it requires

that hydrogen adequate to the vehicle's mission be stored on the vehicle at high pressure or at cryogenic temperatures. It is also possible to produce hydrogen onboard the vehicle by using reforming techniques to remove the hydrogen from fuels such as methanol, ethanol, gasoline, and diesel. This conversion can be done with about 30–40% efficiency and requires that fuel adequate to the vehicle mission be stored onboard the vehicle. This approach eliminates the complexity of the hydrogen storage system but replaces it with the complexity of a reformer and a hydrogen purification system and produces CO<sub>2</sub> as a by product of the reforming process. It seems likely, based on the considerations of the previous section, that a hydrogen fuel cell combined with an appropriate pulse power system could, in principle, meet the specific power and specific energy requirements for passenger vehicles. It is unlikely, however, that such an arrangement could meet the requirements for most high-performance DOD or industrial platforms.

Hydrogen has the property that, when combusted with oxygen, it produces only water thereby eliminating the CO<sub>2</sub> associated with combusting hydrocarbon or alcohol fuels on vehicles. When combusted with air, it does produce nitrous oxides, but properly designed engines can solve this problem at the cost of producing engines that are somewhat larger than gasoline engines of the same power. The design of hydrogen-based internal combustion engines goes back to the early 1800s and can be considered to be a solved problem. Hydrogen internal combustion engines can most certainly be designed to meet civilian and military transportation requirements. The hydrogen could be supplied from a cryogenic or high-pressure tank or from reformed fuels. This approach is limited by the thermodynamic efficiencies of internal combustion and has the same fuel storage/conversion problems associated with the fuel cells mentioned above. It is not clear that hydrogen as a combustion fuel will prove to be satisfactory or competitive with other alternatives. The cryogenic and high-pressure requirements will be a great impediment to its adoption. This is especially true for DOD applications.

There are, of course, special applications where hydrogen will be the preferred fuel. These include situations where the high gas velocities available from hydrogen are needed (e.g., hypersonic aircraft) or where fuel mass is more important than fuel volume (certain space applications). In general, however, it seems unlikely that hydrogen will prevail as a preferred general purpose or military fuel. This matter has been the subject of extensive debate and will be ultimately resolved by the marketplace.

Regardless of how the debate works out, hydrogen will play an important role in the larger effort to develop economically viable and environmentally acceptable alternative fuels. This is simply because hydrogen is a very important ingredient for these fuels. However, in order to use hydrogen one must obtain it. In general, even though hydrogen is plentiful, it does not exist as a free entity but rather as part of chemical compounds (e.g., as a component of water, natural gas, and biomass). If one envisions using hydrogen as a fuel or in the manufacture of alternative fuels, it is important to gain some insight regarding the costs associated with producing hydrogen on a scale relevant to the U.S. transportation fuels problem. In this regard, it is helpful to examine the capital costs associated with producing an amount of hydrogen equivalent in energy content to that actually needed to power the U.S. transportation system (i.e.,  $2.4 \times 10^6$  BPD of oil equivalent, assuming 100% energy conversion efficiency). Hydrogen has an energy content of about 142 MJ/kg, while a barrel of oil has an energy content of about  $6.1 \times 10^3$

MJ. Thus, the hydrogen production corresponding to the actual energy needed to power the U.S. transportation is about  $10^5$  tons per day (TPD). The actual hydrogen needed would depend on the true energy conversion efficiency. For example, if hydrogen were used directly as a fuel and combusted in internal combustion engines with a net conversion efficiency of 18%, then  $5.5 \times 10^5$  TPD of hydrogen would be required. If the hydrogen were used as a fuel to power PEM fuel cells with 80% conversion efficiencies coupled to electric motors with 90% efficiencies, then about  $1.4 \times 10^5$  TPD would be needed. If hydrogen were employed in a process to synthesize some alternative fuel, then the amount needed would depend on that process. However, the amount needed would likely be appropriately measured in units of  $10^5$  TPD. We will, therefore, use that as the appropriate metric for the discussion regarding the production of hydrogen.

There are several well-known methods for producing hydrogen that involve the commercially proven technologies of reforming gases, gasification, and electrolysis. A discussion of these technologies in the context of hydrogen production has been published by Simbeck and Chang.<sup>8</sup> Other promising approaches have been studied but have not been proved commercially viable. An example is the use of thermochemical cycles for splitting water to produce hydrogen.<sup>9</sup>

In order to gain some insight into the costs associated with the various schemes, table 7 provides rough order of magnitude estimates (ROM) of the capital costs associated with the construction of hydrogen production capability using several of these technologies. The estimates are based on published data.

The first three technologies (SM, BG, CG) are well understood, and the cost estimates are based on equipment that has been used commercially for many years. The SI-MHR, or Sulfur-Iodine (SI) cycle that uses heat from a modular helium reactor (MHR) for the necessary thermal energy, is a proposed system that has been well studied but for which the major components are under development. The electrolysis technology for the CE-NR system is well understood, but the unit cost used for the nuclear reactor is at the low end of estimates appearing in the current literature. Thus, the SI-MHR and CE-NR estimates are likely to be optimistic. It is clear from table 7 that by far the lowest capital costs for producing hydrogen are associated with steam reforming of methane (SMR). As a result, the SMR process produces most (95%) of the hydrogen used in the United States today.

The production of  $\text{CO}_2$  is significant for several of the schemes shown in table 7. For example, hydrogen production by current industrial SMR processes produces about 9.5 tons of  $\text{CO}_2$  for each ton of hydrogen. Hence, SMR production of 100,000 TPD hydrogen will result in about 950,000 TPD of  $\text{CO}_2$ . Conventional coal gasification schemes produce about 20 tons of  $\text{CO}_2$  for each ton of hydrogen produced, resulting in  $2 \times 10^6$  TPD of  $\text{CO}_2$  per 100,000 TPD of hydrogen. Biomass gasification is somewhat more complicated regarding  $\text{CO}_2$  production, because the carbon that is gasified to produce hydrogen originated in the atmosphere. In that sense, the process is  $\text{CO}_2$  neutral. There may, however, have been  $\text{CO}_2$  produced in the process of growing the biomass that would need to be taken into account regarding the  $\text{CO}_2$  balance. The SI-MHR and CE-NR schemes would produce no  $\text{CO}_2$ .

Hydrogen production technology	ROM of capital costs for 100,000 TPD capability of hydrogen production (billions of dollars)	Basis of capital cost estimates	Process Energy efficiency
Steam reforming of methane (SMR)	31	Mintz et al. <sup>10</sup>	70%
Biomass gasification (BG)	92	Spath et al. <sup>11</sup>	46%
Coal gasification (CG)	94	Buchanan et al. <sup>12</sup>	44%
Sulfur Iodide Cycle powered by high temperature nuclear reactor (SI-MHR)	194	Schultz et al. <sup>9</sup>	50%
Conventional electrolysis of water powered by a nuclear reactor (CE-NR)	360	Ivy for CE, <sup>13</sup> \$1500/KW <sub>e</sub> for NR	25%

**Table 7.** ROM of Capital Costs Associated With Producing Hydrogen Equivalent of the Energy Actually Needed to Power the U.S. Transportation System.

If the matter of what to do with the CO<sub>2</sub> produced by the above processes can be satisfactorily resolved, then the SMR process would likely remain the preferred means for producing hydrogen on a large scale, as long as methane gas is readily and economically available. The recent advances in the use of hydraulic fracture for the production of natural gas from shale may help in the near term. In the long term, exploitation of gas hydrates could become important to ensure the continuing supply of methane needed for SMR. If the CO<sub>2</sub> disposal problem cannot be resolved, and large amounts of hydrogen are needed then biomass gasification, thermochemical cycles, electrolysis, or some other method of production will need to be considered. There will be feedstock issues (e.g., availability of required biomass, uranium, and water) that may limit the applicability of each of these approaches. Some of these issues will become apparent in the following sections.

According to table 7, the capital costs for producing a quantity of hydrogen gas with the energy equivalent of 2.4 million barrels of oil per day are estimated to range from about 31 billion dollars (the SMR process) to about 360 billion dollars (the conventional electrolysis process using nuclear electric power). These costs do not include capital costs associated with feedstock acquisition and delivery, hydrogen liquefaction (if used), storage and distribution of the hydrogen or if necessary the disposition of the CO<sub>2</sub> produced.

The capital costs provide a sense of the scale of the undertaking and the funds that need to be invested or borrowed in order to proceed. They do not, however, translate directly into the cost of the produced product. The cost of the product produced depends on

factors such as operating costs, feedstock prices, interest rates, payback time for the borrowed money, and tax rates. These factors can be quite variable and are difficult to project into the future with any degree of certainty. This paper will, therefore, not attempt to estimate product prices for fuels produced by different approaches.

We now turn to discussion of several methods of producing alternative liquid transportation fuels. For most of the alternative fuels considered in sections 6–10, the production of hydrogen is a dominant cost. Moreover, in many cases the hydrogen production schemes discussed in this section are integral to alternative fuel synthesis.

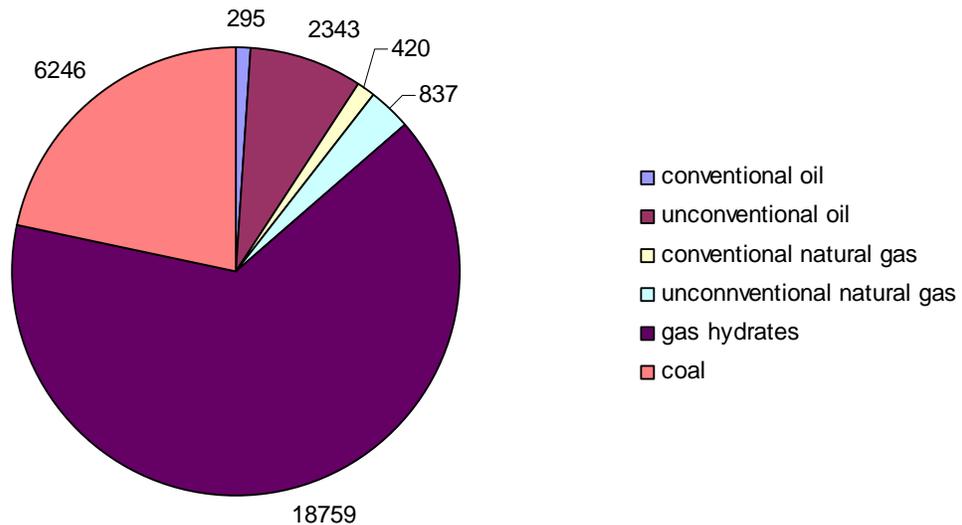
## 6. Liquid Transportation Fuels from Reforming and Gasification

Today, the primary feedstock for transportation fuels is a natural resource, petroleum. One of the reasons for looking beyond petroleum is the growing concern regarding its future availability. It is widely believed that petroleum and other fossil fuels were created over millions of years from the oils (lipids) of plants and animals. This process was highly inefficient. For example, Dukes<sup>14</sup> estimates that, at current consumption rates, one year's worth of energy derived from fossil fuel required  $10^{26}$  Joules of solar energy to produce the plant and animal life needed to make the fossil fuel. That corresponds to an energy efficiency of about  $3 \times 10^{-6}$ . The practical consequence of this is that, today, petroleum is being extracted at a much faster rate than it is being created. As a result, petroleum will ultimately be depleted to the point where it is no longer a viable feedstock for fuels. There is general agreement that this will happen, but considerable disagreement as to when it will happen. Perhaps the most referenced work in this area is that of M. K. Hubbert, who in 1956 predicted that U.S. oil production would peak in 1970,<sup>15</sup> and in 1969 predicted that world oil production would peak in 2000. Hubbert's prediction that U.S. oil production would peak in 1970 turned out to be correct. His prediction that world oil production would peak in 2000 does not appear to have been correct, and there remains considerable speculation as to when world oil production will peak. There is, however, a growing consensus that it would be prudent to look beyond conventional petroleum.

Carbon-based transportation fuels (e.g., hydrocarbons and alcohols) have many attractive features. They also have the property that, when combusted with air or reformed, they produce  $\text{CO}_2$  as a byproduct. In most cases, the synthesis of carbon-based fuels will also produce  $\text{CO}_2$ . In spite of this latter property, it is necessary to have an understanding of how one can synthesize hydrocarbon and alcohol fuels, because they are likely to remain the dominant transportation fuel.

The hydrocarbons are just combinations of carbon and hydrogen, and the alcohols are combinations of carbon, hydrogen, and oxygen. The synthesis of carbon-based fuels is a matter of carbon chemistry about which a great deal is known. In order to undertake such chemistry one must have sufficient feedstocks of carbon, hydrogen, and oxygen. Hydrogen and oxygen are, of course, constituents of water and can be considered, in a global sense, to be in unlimited supply.

Where do we get the carbon we need? Obvious sources of carbon are the earth's hydrocarbon resources and the earth's biomass resources. Some insights into the available hydrocarbon resources can be gained from figure 10.



Source: H.H. Rogner "An Assessment of World Hydrocarbon Resources", Annu. Rev. Energy Environ. 1997 22: 217-262

**Figure 10.** Assessment of World Hydrocarbon Resources (Gtoe).

This figure summarizes the findings from a recent assessment of world hydrocarbon resources in units of Gtoe ( $10^9$  tons of oil equivalent). It is clear that the current principle feedstock, conventional petroleum, represents a very small fraction of the earth's potentially available hydrocarbon resources. If it were possible to access all the hydrocarbon resources indicated by figure 10, then, from a purely energy perspective, the energy needs of the earth could be met for thousands of years. There would, of course, be profound environmental considerations associated with such an undertaking. In reality, most of the hydrocarbon resources indicated by figure 10 will not be economically or technologically accessible. Nevertheless, if only a fraction of them can be harvested in a cost-effective and environmentally acceptable fashion, then the long-term prospects for satisfying the world's transportation energy needs are quite promising.

The unconventional oil indicated in figure 10 includes oil shale and tar sands. Unconventional natural gas includes coal bed methane, gas from fractured shale, and tight-formation gas. In this regard, it has been estimated that recent advances in the use of hydraulic fracture techniques for the extraction of gas from shale may increase the potentially available U.S. natural gas supply by about one-third.<sup>16</sup> This results in a U.S. natural gas supply of about 100 years at current usage rates. Gas hydrates actually fall under the category of unconventional natural gas but have been separated out because of the unique chemical configuration in which they occur and the estimated size of the vast store of gas contained in this configuration. If one could economically and safely access the gas hydrates indicated in figure 10, then the methane derived would have the potential to provide natural gas for thousands of years. This could have a direct impact on

transportation fuels, because natural gas can be straightforwardly employed to synthesize alcohol and hydrocarbon fuels. We will discuss this next.

### Liquid fuels via steam reforming of methane

All of the hydrocarbon resources shown in figure 10 have the potential for being converted into transportation fuels (liquid or gaseous). Perhaps the simplest case for purposes of illustration to consider is the indirect conversion of natural gas into methanol.

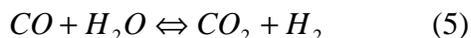
As background with regards to practicalities for this sub-section discussion: methanol has an effective octane of 119 compared to 87–93 for gasoline. This results in a higher auto ignition temperature for methanol. As a result, methanol internal combustion engines can operate with higher compression ratios than can gasoline engines. As noted earlier, the thermal efficiency of internal combustion engines increases as the compression ratio increases. In this regard, Brusstar et al.<sup>17</sup> have operated a methanol-powered internal combustion engine with a compression ratio of 19.5:1 and demonstrated a thermal efficiency of greater than 40%. This exceeds the efficiencies of gasoline and diesel engines and also that of methanol-powered fuel cell engines. As compared with gasoline and diesel power, methanol internal combustion, depending on the achieved engine energy efficiency, would require more fuel due to its specific energy being about half that of gasoline. Gallon for gallon, methanol combustion produces about half the carbon dioxide of gasoline combustion. Hence, at equal engine energy efficiencies, it would produce about the same amount of carbon dioxide, because about twice as much methanol would need to be combusted. If the methanol engine energy efficiency were double that of the gasoline engine that it replaced, it would produce about half the carbon dioxide of gasoline combustion. On the basis of this, one could argue that methanol combusted in a high compression ratio engine could be a viable transportation fuel.

We here describe the most common way to make methanol. The process begins with steam reforming of methane (SMR), where methane ( $\text{CH}_4$ ) is the principal constituent of natural gas. SMR is shown in table 7 to be the cheapest way to make hydrogen on a large scale. In an elementary sense, SMR proceeds according to the reaction

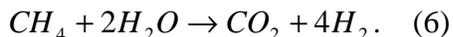


This reaction requires a catalyst (usually nickel), and the steam is usually in the 800–900 °C range.

If one desires to maximize the production of hydrogen, the water gas shift (WGS) reaction



is also employed to yield the overall SMR reaction for the production of hydrogen



At this point it is helpful to remember that mass is conserved in a chemical reaction. Thus, knowing the mass numbers of each element in a reaction allows a simple determination of the quantity of feedstock needed to produce a particular product. The mass number of hydrogen is 1, carbon is 12, and oxygen is 16. If one expresses mass in tons, then the SMR reaction says that 16 tons of methane combined with 36 tons of water

(steam) produces 44 tons of carbon dioxide and 8 tons of hydrogen. Said another way, each ton of hydrogen desired will require 2 tons of methane and 4.5 tons of water and will produce 5.5 tons of carbon dioxide. So far we have neglected the fact that the steam must be heated to about  $800^{\circ}\text{C}$  in order for the reaction to proceed. The energy to do this is taken from the methane supply and consumes about 1.5 tons of methane and produces an additional 4 tons of carbon dioxide per ton of hydrogen. Thus, for each ton of hydrogen produced, the net methane consumption is about 3.5 tons, and the net carbon dioxide production is about 9.5 tons. This simple arithmetic allows one to estimate the SMR feedstock (methane and water) required and the carbon dioxide produced for a given amount of hydrogen.

For simplicity, we introduce a simple “product” energy efficiency  $\eta_p$  where

$$\eta_p = \frac{E_p}{E_{FS} + E_S} . \quad (7)$$

In this equation,  $E_p$  is the calorific content of the product produced,  $E_{FS}$  is the calorific content of the feedstock consumed and  $E_S$  is the calorific value of any supplemental energy that was supplied to the process. This efficiency measures only the energy of the fuel product produced relative to the energy that was required to produce it. It does not give credit to the value of byproducts of the process, such as cogeneration of electricity from waste heat or the calorific or sales value of chemical byproducts. While the energy and market value of the byproducts are important, the interest in this paper is the transportation fuel product of a synthesis process. We will use this simple product energy efficiency as a metric for comparing the various process considered.

Hydrogen has a chemical energy content of about 142 MJ/kg, and methane has a chemical energy of about 55.5 MJ/kg. Since it takes 3.5 kg of methane to produce 1 kg of hydrogen, it follows that  $\eta_p = .73$  when SMR is used to produce hydrogen. In practice, the energy efficiency for SMR for hydrogen production is found to be between .6 and .7.

Instead of producing hydrogen from SMR, one can produce methanol by sending the products of eq. (4) to a methanol synthesis reactor, which typically operates at a temperature of about  $250^{\circ}\text{C}$  and pressures of 50–100 atmospheres and employs a catalyst to favor the reaction



The actual chemistries of SMR and methanol synthesis are somewhat more complicated than that shown above. However, for the purpose of this discussion, the simplified chemistry is adequate. In practice, the energy efficiency from methane to methanol is found to be about 60%.

The capital cost for a methanol plant that implements the above chemistry is dominated by the capital costs for the methane reforming and syngas conditioning steps. These account for about 80% of the plant costs.<sup>18</sup> One can, therefore, obtain a rough estimate of the capital cost for a methanol capability by estimating the capital cost for producing the needed hydrogen using SMR technology and increasing that estimate by 20%. For

example, to do an in-kind replacement of the  $13.4 \times 10^6$  BPD of petroleum used for transportation would require about 250 billion dollars of capital investment for a methanol output with an energy equivalent to the petroleum used by today's U.S. transportation system. If one used a hydrogen production method other than SMR, the capital costs would depend on the scheme chosen.

Various attempts have been made to eliminate the expensive reforming step in methanol production by developing processes that convert methane directly into methanol. However, after decades of work, direct methane conversion is not yet competitive with conventional processes. This is largely due to the fact that methane is a fairly chemically inert compound. Further, as with all carbon sources for fuels, the chemical properties of methanol need to be considered in evaluating its suitability as a fuel. For example: its low volatility can cause starting problems at cold temperatures, it can dissolve certain materials typically used as engine seals, it is corrosive to some metals, it is toxic and it is hydrophilic. These properties would need to be considered in assessing methanol as viable transportation fuel. Details of methanol's physical and chemical properties and material safety data sheets can be accessed via <http://cetiner.tripod.com/Properties.htm>.

The SMR process can also be employed to make liquid transportation fuels other than methanol. One such approach utilizes the methanol process discussed above. There are well-established techniques for converting methanol to gasoline. In particular, in the 1970s a process now called MTG (methanol to gasoline) was developed by Mobil Oil. Some insights into that process can be found in Meisel et al<sup>19</sup>. The details of the process are too complex to cover here. However, it is efficient at converting methanol to gasoline. The overall energy efficiency (including recycled heat) of the MTG process is about 90%. Thus, the energy efficiency of the SMR through MTG process is about 54%. One of the problems that has been identified with this approach is that the gasoline product contains about 40% aromatic hydrocarbons (e.g., toluene, xylenes, and trimethylbenzene), putting it in conflict with current environmental laws. It is problematic whether this process should be pursued as an alternative to petroleum-derived gasoline.

### **Liquid fuels from coal**

It was shown above in illustrative detail that methanol or gasoline can be made by using methane as a feedstock. In that case, the approach employed was to cause the methane to react with hot steam so as to produce a new gas consisting of carbon monoxide and hydrogen. This gas is referred to as "syngas." The syngas was sent to a reactor that was designed to cause the carbon monoxide and hydrogen to react so as to produce methanol. Adding the MTG process step provides a pathway to gasoline. There are many other feedstocks that can be employed for liquid fuel synthesis. This section will discuss the use of coal as a feedstock for the production of liquid transportation fuels.

The total recoverable coal in the United States is estimated to be 280 billion tons (EIA 2003). At the present rate of consumption, this resource will last about 280 years. In light of the size of these reserves, it is reasonable to consider what would be required to utilize this resource as a feedstock for liquid transportation fuels. There are well-known processes that accomplish this. One approach that has been considered is to pyrolyze (i.e.,

heat in an inert atmosphere) the coal in order to drive off the volatile matter (tar, light oils, hydrogen, etc.) that might be amenable to distillation techniques for the production of liquid fuels. This process has been studied for years. It has been found that, because the volatile matter in coal is typically 20–40 percent, pyrolysis results in a large fraction of solid char, which is principally carbon. As a result, pyrolysis, while it has many uses, has not been heavily utilized for fuel synthesis, because fuel synthesis wishes to maximize the conversion of carbon into a hydrocarbon or alcohol fuel.

A second scheme attempts direct liquefaction through hydrogenation of coal. In some sense this scheme can be viewed as replacing the inert atmosphere in pyrolysis with a hydrogen atmosphere that can react with carbon in coal to produce more distillable liquids and less char. Friedrich Bergius and his colleagues studied this approach during the period from about 1912 through WWI and found that they could obtain reaction products that were mostly distillable liquids. The process, however, was slow and required gas pressures up to 700 atmospheres to obtain a large fraction of distillable liquids. In 1931, Bergius received the Nobel Prize in chemistry for his work on chemical reactions under high pressure (this recognition included his work on direct coal liquefaction). The Bergius process for coal liquefaction was scaled to commercial production levels and contributed to the German war effort during WWII. This high-pressure, direct liquefaction process probably has the highest carbon conversion efficiency of the various coal liquefaction schemes. However, the very high pressure needed to obtain large fractions of distillable liquids has discouraged widespread industrial application of this approach.

A third scheme also developed in Germany in the 1920s by Franz Fischer and Hans Tropsch has become the method generally used to synthesize liquid fuels from coal. This method is called indirect liquefaction and is similar to SMR, in that it involves gasifying the coal to create a gas (called syngas) that is predominantly CO and H<sub>2</sub>. This gas is essentially the basis for producing hydrogen by coal gasification mentioned earlier. In the present case, a different synthesis route from that described above for SMR is followed. The syngas is purified and then used as the feedstock for a process known as Fischer-Tropsch or FT synthesis. The FT process involves a complex catalyzed chemistry that produces a variety of products, including paraffins, olefins, alcohols, and carbon dioxide. While coal is primarily carbon, it is not a pure chemical compound but rather is a mix of substances, usually including carbon, hydrogen, oxygen, sulfur, and nitrogen. For example, for bituminous coal the average formula is CH<sub>0.8</sub>O<sub>0.1</sub>N<sub>0.02</sub>S<sub>0.02</sub>. A proper analysis of the FT process applied to coal would deal with all of its constituents. For simplicity, we will assume that coal is just carbon. The basic FT synthesis process proceeds according to the reactions



The first reaction produces olefins, or alkenes, (C<sub>n</sub>H<sub>2n</sub>), while the second reaction produces paraffins, or alkanes, (C<sub>n</sub>H<sub>2n+2</sub>). As an example, when n = 8, the reader will recognize the paraffin product as octane. The FT process always produces a mix of olefins and paraffins. However, the details of the mix depend on the reactor conditions

and the catalyst used. The FT reactors are generally operated in a low temperature range of 200–240 °C or a high temperature range of 300–350 °C. Low-temperature operation favors high molecular weight waxes, while high-temperature operation favors low molecular weight olefins. The route to diesel fuel is through the low-temperature process while the route to gasoline is the high-temperature process. In both cases, product upgrading is required.

Since the FT process requires an input gas consisting of carbon monoxide and hydrogen, any process that provides such a gas is a potential candidate for creating the input gas. However, it can be seen from the governing chemical equations that maximum use of carbon in FT synthesis occurs when the input gas contains about two hydrogen molecules for each carbon monoxide molecule. Thus, a process like SMR, which creates a mixture of three hydrogen molecules for each carbon monoxide, is not, by itself, a good candidate for preparing the input gas for FT synthesis. Some modification of the SMR process, such as adding pure oxygen (autothermal reforming), would be desirable in order to use methane as the feedstock for FT synthesis. Such approaches have been considered.<sup>20</sup> These methane conversion schemes can be expected to have thermal efficiencies similar to the 60% efficiency that is characteristic of SMR.

Other methods of syngas preparation for FT synthesis are well developed. One such approach is the gasification of coal. Because of their general importance in the field of synthetic fuels, we have included a brief discussion of coal gasification coupled to the FT synthesis process in appendix B. A more detailed discussion can be found in Probst and Hicks.<sup>2</sup> The simple analysis presented in appendix B suggests that one ton of coal will produce two barrels of oil equivalent product. This is similar to the industrial experience. From this one can estimate the process energy efficiency. The calorific energy content of one ton of coal is about  $2.8 \times 10^{10}$  Joules, while the energy content of a barrel of oil is about  $6.1 \times 10^9$  Joules. Since most of the energy for this process comes from the coal feedstock, one finds that the process energy efficiency of coal gasification coupled to FT synthesis will be about 44% for the liquid fuel product. There are, of course, other energy credits that can be given. For example, FT is a very exothermic process, and perhaps a 7% energy credit is available from cogeneration of electrical power. Other products, such as heavy waxes, have potential value. However, our interest here is the process energy efficiency to the desired transportation fuel. That efficiency is about 44%.

The combination of coal gasification and FT to produce liquid fuel is generally referred to as “coal to liquid” (CTL) conversion. The CTL process is well understood and could, in principle, be employed to provide for all U.S. transportation fuels. Such an undertaking would involve significant feedstock requirements and would also present significant carbon dioxide management issues.

The feedstock issue is easily quantified. The current rate of coal production in the United States is about  $10^9$  tons per year. Most of this is used to provide the United States electrical generating capacity. Since U.S. electrical consumption is unlikely to decline, any effort to provide transportation fuel from coal will require coal in addition to that which is currently mined. The United States consumes about  $5 \times 10^9$  barrels of oil per year for transportation purposes. At a conversion rate of two barrels of oil per ton of coal, total oil independence at today’s transportation fuel consumption would require that an

additional  $2.5 \times 10^9$  tons of coal be mined each year, resulting in annual coal consumption of  $3.5 \times 10^9$  tons. Hence, if we were to provide for our current uses of coal and fill our current transportation-related petroleum needs by a conventional CTL process then the current coal reserves of 280 years would be reduced to about 80 years. A 1.4% annual growth in consumption would reduce that to about 50 years and a 5% growth would reduce it to about 30 years. While these estimates are only approximate, it is clear that the use of the conventional CTL process to resolve any significant fraction of the nation's transportation fuel problem would have a profound effect on the nation's coal resources in a relatively short time. Nevertheless, it is clear that CTL could, in principle, provide for U.S. transportation fuel needs for an extended period. This would roughly double the  $\text{CO}_2$  production associated with transportation, because the CTL process itself produces about as much  $\text{CO}_2$  as does the combustion of the FT-produced liquid fuel. Since the CTL process is centralized, most of the  $\text{CO}_2$  produced by it could be captured. The captured  $\text{CO}_2$  could be converted to additional fuel by processes that will be discussed later. This would be expensive but would reduce the amount of coal that needed to be gasified. . Also, if permitted, the captured  $\text{CO}_2$  could be sequestered. In this regard, one should keep in mind that after about 80 years one would have sequestered about half the carbon in the U.S. coal supply in the form of gaseous  $\text{CO}_2$ .

It is logical to inquire whether modifications to the conventional CTL process could reduce its coal consumption. A significant amount of the coal consumption calculated above is driven by an inadequate supply of hydrogen in the feedstock for the FT process; see appendix B (the Gasification and Fischer-Tropsch Process). This situation could, in principle, be improved by injecting into the output of the coal gasifier an appropriate amount of supplemental hydrogen. The precise amount of hydrogen required depends on the detailed kinetics of the gasifier. The example discussed in appendix B indicates that the hydrogen available from gasification designed to optimize the production of hydrogen and carbon monoxide (the feedstocks for the FT process) is about 50% of what is needed for the optimum syngas for the FT process. As discussed in appendix B, some improvement in hydrogen production is obtained by using the gas water shift (WGS) reaction. This, however, is wasteful of carbon and has already been included in the analysis that leads to the estimate of two barrels of oil per ton of coal. If one eliminated the WGS step and instead injected a supplemental amount of hydrogen into the syngas that was equal to that being produced by the gasifier, then the resulting syngas would be ideal for the FT synthesizer. This step would reduce the coal requirement by about 33% for the same FT product, resulting in about three barrels of oil equivalent per ton of coal gasified. This rate of coal conversion leads to a CTL coal requirement of about  $1.7 \times 10^9$  tons per year and a total coal requirement of about  $2.7 \times 10^9$  tons per year. At this rate, the lifespan of the current U.S. coal supply would be reduced to about 105 years, assuming no additional growth in use. This is 25 years longer than CTL without supplemental hydrogen. The price one pays for this coal supply lifetime extension is the need to provide about  $5 \times 10^5$  TPD of supplemental hydrogen. This is about the amount of hydrogen that would be needed to provide for a hydrogen internal combustion engine solution to the entire transportation fuel problem. The supplemental hydrogen infrastructure would itself be a massive complex.

It is straightforward to estimate the capital cost of the combined CTL and supplemental hydrogen infrastructure. Using National Mining Association estimates, one finds that a

13.4x10<sup>6</sup> barrel per day conventional CTL capacity would cost about 900 billion dollars to construct.<sup>21</sup> The provision of supplemental hydrogen should reduce the capital cost of the coal gasification component of that capability by about 300 billion dollars. The cost of hydrogen production for several different technologies is given in table 7. If one scales these hydrogen production capital costs to those associated with a 500,000 TPD capability, one can estimate the capital cost associated with CTL involving supplemental hydrogen. These estimates are given in table 8.

Hydrogen production technology	ROM of capital costs for 500,000 TPD hydrogen production capability (billion dollars)	ROM of capital cost of 13.4x10 <sup>6</sup> barrel per day CTL capability with supplemental hydrogen (billion dollars)
Steam Reforming of Methane (SMR)	157	757
Biomass gasification (BG)	450	1050
Coal Gasification (CG)	467	1067
Nuclear reactor Sulfur – Iodide Cycle (SI-MHR)	967	1567
Conventional Electrolysis Powered by Nuclear Reactor (CE-NR)	1800	2400

**Table 8.** Estimates of capital costs associated with providing supplemental hydrogen to a CTL capability and the capital costs of the resulting CTL capability when the CTL capacity is 13.4x10<sup>6</sup> barrels per day.

The third column in table 8 should be compared with the conventional CTL capital cost estimate of 900 billion dollars. Of the supplemental hydrogen production schemes considered, only the SMR scheme indicates a net reduction in CTL capital cost. The SMR supplemental hydrogen production would increase CO<sub>2</sub> production by about 5x10<sup>6</sup> TPD and methane consumption by about 1.3x10<sup>6</sup> TPD. This would roughly double the CO<sub>2</sub> produced by the transportation sector and double the rate of consumption of natural gas. The use of coal gasification to produce the supplemental hydrogen makes no sense, because it would consume coal faster than CTL without supplemental hydrogen. The two nuclear schemes considered would increase the lifetime of the coal supply by perhaps 25%, but would require a much larger capital investment than using an SMR approach to supplemental hydrogen or just using a conventional CTL approach without supplemental hydrogen. The gasification of biomass to produce the supplemental hydrogen would extend the lifetime of the coal supply by perhaps 25%, but would have higher capital costs than using SMR or just conventional CTL. It would also introduce the complexity of having to run two separate large gasification infrastructures.

From the above discussion it would seem that the injection of supplemental hydrogen into the CTL process, while possible, would not be practical or cost effective. Another

option to consider would be to perform the entire liquid fuel production using carbon neutral biomass gasification. We will consider that option next.

### Liquid Fuel via Biomass Gasification

In the above two sub-sections we have considered methane and coal as sources of the syngas used for liquid fuel synthesis. These approaches were shown to be capable of providing for the full U.S. transportation fuel needs for significant periods of time. Such use would greatly increase the consumption of coal and natural gas, thereby reducing the lifetimes of those reserves. They would also have the side effect of producing large amounts of additional carbon dioxide.

The synthesis of liquid fuels using the FT process requires a feedstock consisting of carbon monoxide and hydrogen. The preferred ratio of hydrogen molecules to carbon monoxide molecules in the feedstock is 2:1. The FT reactor does not care how the syngas is produced as long as it has been prepared so as to be free of impurities that might poison the FT catalysts and enters the reactor with the proper temperature, pressure and mixture. Therefore, biomass (e.g., hardwoods, softwoods, grasses, crop residues, etc.) gasification provides another potential option for the source of the FT feedstock. The use of biomass feedstocks, if done in a sustainable fashion, avoids much of the carbon dioxide management issue, because the carbon dioxide that is released during the production and use of these fuels comes from the atmosphere. Because of this, the biomass feedstock approach is said to be carbon neutral. This statement is true to the extent that fossil fuels are not used to grow and harvest the biomass. In this sub-section we will discuss the extent to which biomass gasification can address the transportation fuels problem. The combination of biomass gasification with FT synthesis is referred to as BTL.

The chemical makeup of biomass has been well studied and catalogued (see for example [http://www1.eere.energy.gov/biomass/feedstock\\_databases.html](http://www1.eere.energy.gov/biomass/feedstock_databases.html)) Dry biomass is composed of cellulose, hemicellulose, lignin, protein, and ash. The fractions of these compounds vary with the type of biomass. However, on average, the composition is as follows:

Compound	Weight Percent
Cellulose (45% carbon)	44
Hemicellulose (48% carbon)	27
Lignin (40% carbon)	20
Other	9
Total	100

**Table 9.** Average chemical composition of dry biomass (hardwoods, softwoods, grasses, crop residue, etc.).

From this table we see that, on average, carbon accounts for about 41% by mass of biomass. We can use the previous analysis of the CTL process to gain some understanding of the ability of biomass gasification to contribute to a solution of the transportation fuels problem. The most plentiful form of coal in the United States is bituminous coal, which has an average carbon content of about 70%. Thus, one can expect that the production of FT liquids from the gasification of biomass will require about 1.7 times the mass of coal needed for the equivalent liquid product production from the CTL approach. This results in a dry biomass requirement of about  $4 \times 10^9$  tons per year to produce a FT product with energy content approximating that currently consumed in U.S. transportation fuel. A recent study by the Department of Energy and the Department of Agriculture concluded that about  $1.4 \times 10^9$  tons per year of biomass could be recovered from U.S. forest resources and agricultural resources in a sustainable fashion without adversely impacting the forest and agriculture industries.<sup>22</sup> This would be a significant undertaking and involve a “more than seven-fold increase in production from the amount of biomass currently consumed for bioenergy and biobased products.” One can conclude from this that an aggressive biomass gasification program could produce at most about one-third of the current U.S. transportation fuel requirement. While this is a crude estimate, it suggests that it will be difficult for biomass gasification alone to provide, on a sustainable basis, the liquid fuel equivalent of the  $13.4 \times 10^6$  BPD of oil now used for the current U.S. transportation system.

It should be noted that biomass gasification chemistry is somewhat different from coal gasification chemistry. This is because cellulose is the basic building block of biomass, resulting in a chemical structure based on the  $C_6H_{10}O_5$  complex. This is quite different from the average chemical formula for bituminous coal,  $CH_{0.8}O_{0.1}$ . As a result, the output from the biomass gasifier includes significant water, methane, and tar. It is, therefore, necessary to include a reforming step that converts the methane and tar into carbon monoxide and hydrogen prior to entering the gas cleanup apparatus and the FT reactor. An example of how to perform this gasification and reforming has been reported by Spath et al.<sup>11</sup> and is the basis for the capital costs quoted in table 6 for hydrogen production by biomass gasification. In that case, the gas that leaves the tar reformer has a hydrogen to carbon monoxide ratio of 2.03:1, which is about what is required for complete consumption of carbon monoxide in an FT reactor. Unlike CTL, where there is substantial experience regarding capital costs, there are no large commercial BTL plants from which one can scale BTL capital costs. However, it is known that about 70–75% of the capital costs in the production of syngas from gasification are associated with the syngas production, gas conditioning, and power generation, while 10–20% are associated with FT synthesis and product upgrading. If one assumes that a similar breakout of costs will occur for BTL systems, then one can utilize the analysis reported by Spath et al.<sup>11</sup> to provide a rough estimate for the capital cost for a BTL facility that produces  $13.4 \times 10^6$  barrel per day of FT liquid product. We saw above that this will require about  $4 \times 10^9$  TPD of dry biomass, or  $1.1 \times 10^7$  TPD. The Spath et al.<sup>11</sup> estimates for hydrogen production were based on a 2000 TPD biomass input to the gasifier. If we simply scale the Spath et al.<sup>11</sup> capital cost estimate of 154 million dollars to the required biomass input, we obtain 893 billion dollars, which is quite similar to the CTL estimate of 900 billion dollars for the same quantity of FT liquid product. In reality, a BTL capital investment would likely be

limited to about 300 billion dollars because of the limit on the availability of biomass that was mentioned above. As noted earlier, this capability would provide for about one-third of the needed fuel.

It is straightforward to make a rough estimate of the BTL process energy efficiency. It takes about 1.7 tons of biomass to produce two barrels of oil equivalent liquid by the BTL process. A ton of dry biomass has a typical calorific value of about  $1.5 \times 10^{10}$  Joules, while a barrel of oil has a calorific value of about  $6.1 \times 10^9$  Joules. These numbers suggest that the BTL process has an energy efficiency of about 47%. As expected, this is comparable to the process efficiency of 44% found for the CTL process.

There are several other methods for producing transportation fuels from biomass. A method employing fermentation technology will be discussed in section 7.

## 7. Enzymatic Approach to Producing Fuels from Biomass

It was pointed out previously that the carbon in biomass is contained principally in carbohydrates and in lignin. The carbohydrates (cellulose, hemicellulose, and starch) are composed of sugars or polymers of sugars. Lignin is not a carbohydrate and is not amenable to the processes describe below. It has been known for millennia that certain sugars can be fermented (anaerobically decomposed into alcohols and carbon dioxide) in the presence of enzymes (complex proteins that are produced by cells and act as catalysts in specific biochemical reactions). The reduction of carbohydrates to these sugars is a key step in the production of alcohol fuels. Perhaps the best known example of such a fuel is ethanol synthesized from cornstarch. The basic process here involves the hydrolysis (decomposition by reaction with water) of cornstarch ( $-C_6H_{10}O_5-$ ) and the fermentation of the resulting Maltose ( $C_{12}H_{22}O_{11}$ ) to produce ethanol ( $C_2H_5OH$ ). The overall reaction can be written as



It follows from eq. (11) that 57% of the corn starch is converted into ethanol. Since about 57% (by weight) of a bushel of corn kernels is starch, it follows that about 33% can be converted into ethanol. A typical bushel of corn kernels weighs about 56 lbs. Thus, a bushel of corn yields about 18.5 lbs, or 2.8 gal. of ethanol. The corn to ethanol process requires about 64% of the energy contained in the ethanol product.<sup>2</sup> This energy is typically provided by burning natural gas. The energy content of bone-dry corn is about 14 MJ/kg. The energy content of methanol is about 30 MJ/kg. Thus, the simple energy efficiency of the corn to ethanol process is about 46%. The capital cost for a large corn ethanol plant is estimated to be about \$1 per gallon per year.

The ethanol equivalent of U.S. oil consumption for transportation is about  $3 \times 10^{11}$  gallons per year. If corn-based ethanol were to provide this, it would require about  $10^{11}$  bushels of corn. The typical productivity of an acre of corn is about 130 bushels. Thus, the process described above would require about  $10^9$  acres of corn production to yield the ethanol energy equivalent of today's transportation fuel needs. This represents about forty percent of the landmass of the United States and exceeds the estimated arable land ( $4 \times 10^8$  acres) available in the United States. Current annual corn production in the United States is about  $10^{10}$  bushels. Most of that is used to feed livestock, poultry, fish, and people. These results indicate that enzymatic production of ethanol using only corn starch as a feedstock is not viable as an approach to provide for U.S. transportation fuel needs. If ethanol were to be the fuel of choice, then other feedstocks must be considered.

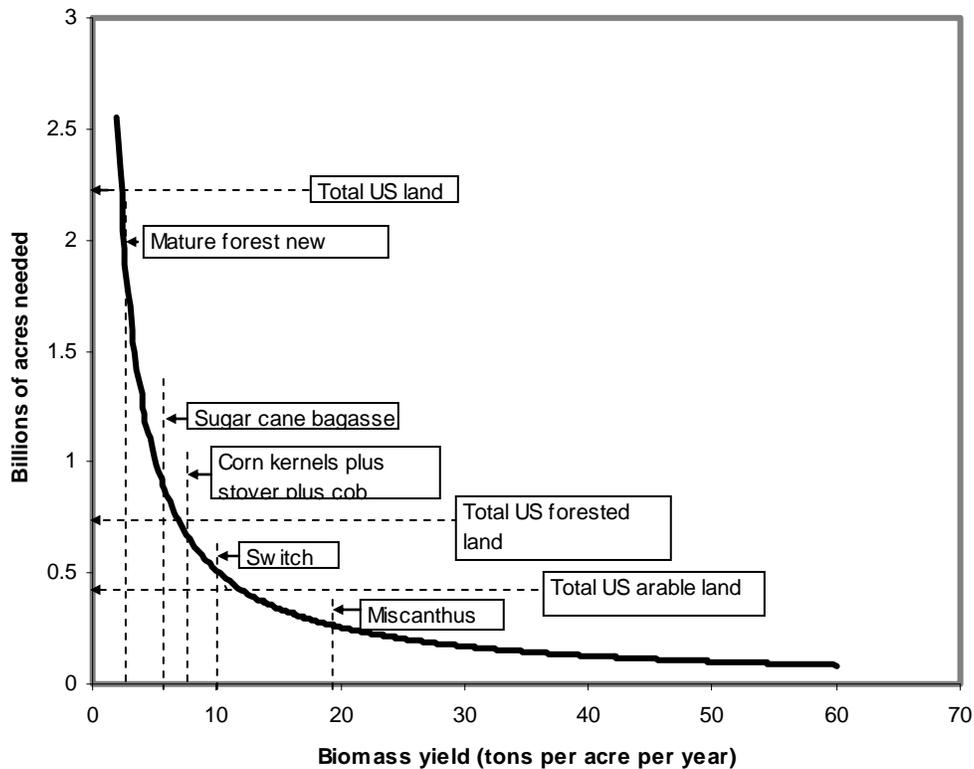
Corn starch is a small fraction of U.S. biomass. It can be seen from table 8 that about 71% by weight of biomass (plants, crops, trees, etc.) resides in cellulose and hemicellulose, both of which are polymers of sugars. If these polymers can be decomposed into sugars that are fermentable, then the basic process discussed above for the production of ethanol can be utilized. This opens up a broad array of crops beyond

corn. Obvious candidates are grain crops, whose seeds, like corn, are high in starch and are easily hydrolyzed to fermentable sugars. Another obvious candidate is sugar crops, because the sucrose from these crops is easily hydrolyzed to fermentable sugars. After the seeds and sucrose have been removed from grain crops and sugar crops, considerable carbon remains in crop residue in the form of cellulose, hemicellulose, and lignin. There are also the lignocellulosic crops, such as grasses, shrubs, and trees. The lignocellulosic residues from crops and lignocellulosic crops have proved to be difficult as feedstocks for fermentation. However, recent developments in the areas of cellulases and xylases show promise for hydrolyzing the cellulose and hemicellulose found in biomass. Considerable work remains to be done to show that the required cellulases can be produced economically on a scale required for synthetic fuel production. However, if one assumes that the ongoing work will be successful, then the application to lignocellulosic biomass will follow a total reaction path similar to that shown in equation (11), but acting on the polysaccharides that make up cellulose and hemicellulose. As a result, 1 g of cellulose or one gram of hemicellulose will yield about 0.57 g of ethanol. Since cellulose plus hemicellulose constitute about 71% of the biomass, it follows that a ton of biomass could, in principle, produce about 0.4 tons of ethanol.

The process of cellulosic ethanol production is much more energy intensive than that for corn ethanol production, and the production plants will be much more expensive to build than are the corn ethanol plants. A plant design study was performed recently to compare the costs of building a lignocellulosic ethanol plant to for the costs of building a corn ethanol plant.<sup>23</sup> The lignocellulose plant utilized a fluidized bed combustor fed by the lignocellulose feedstock to provide for the process energy requirements. The corn ethanol plant employed the much less expensive natural gas boiler to provide the process energy. A 50 million gallon per year lignocellulose plant was estimated to cost about 194 million dollars. The same capacity corn ethanol plant was estimated to cost 48 million dollars. As noted earlier, the corn ethanol approach, while much less expensive, is not viable as a total solution, because there is insufficient landmass to grow the necessary corn. The lignocellulose plant was predicted to produce 79 gallons of ethanol per dry ton of lignocellulose feedstock. If one takes the biomass feedstock as having an energy content of 17 MJ/kg and ethanol as having an energy value of 80 MJ/gal one obtains a simple energy efficiency of about 41% for the lignocellulose plant. This is comparable to the simple energy efficiency calculated above for a typical corn ethanol plant.

The information given above allows one to estimate the number of biomass acres needed to provide from lignocellulose the ethanol energy equivalent of today's U.S. transportation fuel as a function of the lignocellulose biomass yield per acre. This estimate is plotted in figure 11.

**Figure 11. Biomass acres needed to provide the ethanol energy equivalent of today's US transportation fuel from ligno-cellulose vs the ligno-cellulose biomass yield per acre.**



The horizontal dashed lines in figure 11 indicate the total U.S. landmass, the total U.S. forested landmass, and total U.S. arable landmass. The vertical dashed lines indicate the annual new wood growth per acre added to a mature forest, the sugarcane bagasse yield per acre, the corn kernel plus stover (leaves and stalks) plus cob yield per acre, the switch grass yield per acre, and the miscanthus yield per acre. The intersection between these vertical lines and the solid curve provides an estimate of the number of acres needed for a particular feedstock. One can see from figure 11 that there is not enough new growth in mature forested lands to provide the wood to obtain sufficient ethanol from the U.S. forests. The acreage required for sugar cane bagasse or for corn, including kernels, stover, and cob, exceeds the total U.S. arable landmass. The perennial grasses, switch grass, and miscanthus require approximately the total arable landmass. These perennial grasses can grow on land that today would be considered marginal, thereby reducing the impact on food production. However, the biomass yield will likely decline on marginal land. It seems clear that a single crop to ethanol solution will have great difficulty in solving the full transportation fuel problem while at the same time providing for the critical traditional products from agricultural and forested lands.

It was noted earlier that a DOE/USDA study concluded that, with some effort, about 1.4 billion tons of biomass per year could be obtained from the forest and agriculture industries without adversely impacting the ability of those industries to meet their

traditional and essential responsibilities.<sup>22</sup> If cellulosic ethanol becomes a reality, then 1.4 billion tons of biomass could produce about 360 million tons, or about  $10^{11}$  gallons, per year of ethanol. This is about one-third of the ethanol required for a full solution to the transportation fuels problem. It is estimated that the capital cost of a large cellulosic ethanol plant would be about 4 dollars per gallon per year.<sup>23</sup> This leads to a capital cost for converting 1.4 billion tons of biomass into cellulosic ethanol of about 400 billion dollars. This cost should be compared to the estimated capital cost of 300 billion dollars for gasifying the same biomass and producing FT liquids with roughly the same energy content. Thus, within these rough estimates, the biomass to ethanol approach appears have capital costs that are about 30% higher than the BTL approach. The FT product from the BTL approach would likely be more compatible with the current gasoline and diesel infrastructures and with the FT fuels that would need to be produced from other feedstocks that would be needed to make up the two-thirds of the fuel that biomass could not produce in a sustainable fashion.

A factor that we have not discussed involves the non-solar energy that must be invested to grow the biomass. If that energy must come from the biomass-produced fuel, then the energy content of the biomass fuel must be many multiples of the biomass-produced energy invested to grow the biomass in the first place, if the process is to be self sustaining. Also, if the non-solar energy needed to grow, prepare, and distribute the biomass comes from fossil fuels, then the overall process is not carbon neutral. These topics are beyond the scope of this paper but have been matters of some controversy in the bio-energy field for some time.

A DOD-only solution using biomass requires only one 50<sup>th</sup> of the acreages shown in figure 11. In principle, a DOD solution could be accommodated with any of the biomass sources indicated in figure 11. However, the required landmasses are still large. For example, a corn kernel solution for DOD would require about 30 million acres. The entire U.S. corn production involves about 90 million acres, of which only about 4 million acres are currently dedicated to ethanol production. Even a DOD-only solution would have a large impact on the U.S. forestry and agriculture industries.

## 8. Fuels from Biomass Oils

In the above discussion we have discussed the topic of synthesizing fuels from biomass. There are also natural oils that occur in biomass (seeds, animal fats, etc.) that provide another potential approach to alternative transportation fuels. Fuels made from natural oils are generally referred to as biodiesel fuels. About 95% of biomass oils are triglycerides (three fatty acids plus glycerol). There exists a mature biorefinery industry that produces a large number of products (soaps, detergents, lubricants, solvents, etc.). The basic technology employed here is well developed. The process consists of a crushing step where the bio oil is separated from the feedstock (e.g., soy beans) and an oil conversion step that converts the triglycerides in the bio oil into biodiesel (methyl ester) and glycerine. In the oil conversion process, 1 kg of bio oil produces about .97 kg of biodiesel and .2 kg of glycerine and consumes about .1 gram of methanol. The predominant bio oil feedstock used in the United States is soybean. We will use soy beans as an illustrative example.

Bio oil constitutes about 19% by weight of the soybean. Thus, a 1 kg bio oil input requires about 5.3 kg of soybean. The calorific energy content of soybean is about 18.7 MJ/kg. The calorific energy of biodiesel is about 37 MJ/kg, and the calorific energy content of methanol is about 19.7 MJ/kg. A detailed study of the life cycle of biodiesel produced from soybean found that about 17% of the biodiesel product energy was required to be added in the crushing and conversion steps of the process.<sup>24</sup> From these numbers one finds that the simple process-energy efficiency of the biodiesel process from soybean feedstock to biodiesel product is about 35%.

The biodiesel lifecycle report mentioned above provides some data regarding the capital cost of constructing biodiesel plants. While there is considerable variability in the data, a capital cost of about \$1 per gallon per year of biodiesel product is representative of the cited capital costs. Thus, if one were able to provide the bio oil feedstock needed to produce the  $2 \times 10^{11}$  gallons per year needed for a biodiesel solution to the national transportation fuels problem, the capital cost involved would be in the vicinity of  $\$2 \times 10^{11}$ . This is comparable to the capital cost estimated earlier for methanol solution using SMR.

There are other plant and vegetable oils that can be used for feedstock for biodiesel production. Among these are corn oil, sunflower seed oil, peanut oil and palm oil. The biodiesel yields for these crops are well known and are listed in table 10.

Oil Crop	Biodiesel yield in gals/acre	Annual MJ/acre
Corn	14	1,746
Soybean	40	4,988
Peanut	90	11,223
Avocado	225	28,0575
Palm	500	62,350

**Table 10.** Biodiesel yield from several bio oil crops.

One could use table 10 to estimate the number of acres that would be needed by each of the various oil crops in order to satisfy the transportation fuel requirements. It is simpler to just compare the oil crop yields with the lignocellulose crop ethanol yields discussed above. These yields are summarized in table 11 for several lignocellulose crops.

Lignocellulose Crop	Ethanol yield in gals/acre	Annual MJ/acre
sugar cane bagasse	475	37,968
lignocellulose corn	634	50,625
switch grass	792	62,280
miscanthus	1,426	114,000

**Table 11.** Ethanol yield for several lignocellulose crops.

The lignocellulose energy yields are seen to be comparable to or greater than the biodiesel crop yields. Therefore, from the point of view of solving the national transportation fuels problem, biodiesel approaches will face even more serious difficulties than those faced by ethanol approaches. This is further complicated by the fact that the high-yield biodiesel crops such as avocado and palm are very limited regarding where they can be grown. The NREL biomass oil analysis study mentioned above concluded that the ultimate supply potential for bio oil fuel is about 10 billion gallons per year. This represents about 5% of the U.S. transportation fuel need. The addition of biofuel from animal fats does not significantly change this result. Thus, while bio oils and biodiesel fuel may have important niche applications, they are not a solution to the national transportation fuel problem.

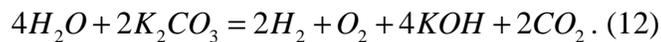
There is one potential, although unlikely, exception to the bio oil conclusion. It has been conjectured that certain algae may produce bio oil yields greater than 10,000 gallons per acre. This projected yield derives from results obtained in the Department of Energy Aquatics Species Program (ASP), where algae strains were found having natural oil content as high as 60%.<sup>25</sup> The ASP was initially motivated by the idea of using algae ponds as a way to sequester CO<sub>2</sub> emissions from smokestacks. It was envisioned that CO<sub>2</sub> would be separated from the stack gases and bubbled through a flowing algae pond, where it would be taken up by the algae. The experimental data indicated that certain algae strains were very good, under the proper circumstances, at converting CO<sub>2</sub> and sunlight into oil. As a result, the ASP changed its thrust from that of CO<sub>2</sub> sequestration to biodiesel production. If the projected yield were actually realizable on a large, sustainable, and economically viable scale, it would have a significant impact on the viability of biomass-derived fuels as a solution to the national transportation fuels problem. If successful, the landmass required to meet the national transportation fuel need would be about one percent of the U.S. landmass.

The ASP project found that the conditions that promote high productivity and rapid algae growth and the conditions that induce high oil accumulation seem to be mutually exclusive. Therefore, the conjectured high yields were never achieved in the ASP. There is, however, some hope that genetic manipulation of promising algae strains might

produce strains that are simultaneously capable of both high growth and high lipid (oil) synthesis. The new strains would also have to be able to maintain these properties in the demanding operational environments in which they would ultimately function. Research to achieve these goals is high risk, but, if it were successful, it could have a very large impact. The data needed to assess the efficiency and expected capital cost associated with this approach remains to be obtained.

## 9. Synthetic Fuel from Atmospheric Carbon Dioxide

Among the factors motivating interest in alternative transportation fuels is concern over the buildup of  $\text{CO}_2$  in the atmosphere. In this regard, an obvious approach to consider is the possibility of removing the  $\text{CO}_2$  from the atmosphere at the rate that transportation fuels are adding  $\text{CO}_2$  to the atmosphere and converting that  $\text{CO}_2$  into transportation fuel. This is similar to the biomass approach discussed in the previous sections, except that, in this case, the removal scheme for  $\text{CO}_2$  involves artificial filtration rather than photosynthesis. The extracted  $\text{CO}_2$  could be converted into a transportation fuel which, when consumed, would return the  $\text{CO}_2$  to the atmosphere. The cycle would, therefore, be  $\text{CO}_2$  neutral, provided that the energy source needed to extract the  $\text{CO}_2$  and to make the synthetic fuel was not itself a  $\text{CO}_2$  producer. One approach for doing this was proposed by Stucki et al.<sup>26</sup> This approach involves an absorption/desorption process in which a  $\text{K}_2\text{CO}_3$  (potassium carbonate) solution formed through  $\text{CO}_2$  absorption by  $\text{KOH}$  (potassium hydroxide) is fed to an electrolyzer where  $\text{CO}_2$  and  $\text{KOH}$  are regenerated by the overall reaction



The regenerated  $\text{KOH}$  is returned to absorb more  $\text{CO}_2$ , and the regenerated  $\text{CO}_2$  is converted into methanol through the mildly exothermic reaction



Using experimental results, Stucki et al. designed a one-square-meter module consisting of an array of hollow fibers (240 mm inner diameter) through which a 0.5 molar  $\text{KOH}$  solution would flow at 2 cm per second. The array of fibers provided an absorption membrane area of 18 square meters with a total fiber length of 23,000 m. The air was assumed to flow through the array at 3 m per second. The experimental data indicated that this array would remove 3.7 kg of  $\text{CO}_2$  per hour from an atmosphere containing 350 ppm of  $\text{CO}_2$ . The air was predicted to undergo a 50%  $\text{CO}_2$  depletion as it passed through the array. An electrolysis cell would be used to regenerate the  $\text{KOH}$  and  $\text{CO}_2$  according to reaction (12), and in the process would also generate one-third of the hydrogen needed for the methanol synthesis reaction (13). Additional hydrogen will be needed because, for maximum carbon consumption, reaction (13) requires three hydrogen molecules per  $\text{CO}_2$  molecule, while equation (12) generates only one hydrogen molecule per  $\text{CO}_2$  molecule. The electrolyzer that would regenerate the,  $\text{CO}_2$ ,  $\text{KOH}$  and also supply the needed hydrogen would require about 30 kilowatts of electrical power for the case studied by Stucki et al.

A variation on this approach has recently been studied by Los Alamos National Laboratory (LANL). The LANL scheme, designated as “Green Freedom,” employs a  $\text{K}_2\text{CO}_3$  solution to absorb  $\text{CO}_2$  to form potassium bicarbonate ( $\text{KHCO}_3$ ).<sup>27</sup> Absorption of greater than 95% is claimed. The bicarbonate solution is then sent to an electrolyzer,

where  $\text{CO}_2$  is regenerated along with one molecule of  $\text{H}_2$  for each molecule of  $\text{CO}_2$ . The  $\text{CO}_2$  is then reacted with hydrogen to synthesize methanol according to equation (13). As with the Stucki scheme, supplemental hydrogen must be added to achieve the stoichiometric coefficient required by eq. (13). The methanol produced is then converted to gasoline by the Mobil MTG process mentioned earlier.<sup>19</sup>

Since the Green Freedom results are recent, we will use them to estimate the energy efficiency of the synthesis of transportation fuel from atmospheric  $\text{CO}_2$ . The Green Freedom program proposes to employ conventional electrolysis powered by nuclear reactors. Since the individual processes involved in Green Freedom are well understood, it is possible to make reasonably accurate estimates of the process efficiency and of the capital costs involved in building the production plants. The  $\text{CO}_2$  feedstock has no calorific value. However, it is found that the nuclear fuel must provide about 5.7 Joules of thermal energy for each Joule's worth of gasoline produced. This leads to a simple process-energy efficiency of about 18%. This efficiency could be raised to perhaps 25% if more energy-efficient methods (e.g., SI thermal cycle or high-temperature electrolysis) for producing the supplemental hydrogen proved to be viable. The Green Freedom program estimated the nuclear reactor capital costs based on using the expected costs of the Westinghouse AP1000 third generation pressurized water reactor as the process-energy source. The other components are commercially available, and their capital costs are known. The total system capital cost was found to be about 290,000 dollars per barrel per day of oil equivalent product. This leads to an estimated capital cost of about 4 trillion dollars for a capability equivalent to the  $13.4 \times 10^6$  BPD currently used for transportation. About 58% of the capital cost is due to the nuclear reactor costs. The scheme would require about 1600 three-gigawatt thermal nuclear reactors. For reference, there are about 444 nuclear power reactors in operation around the world.

Other proposals for converting  $\text{CO}_2$  into transportation fuels have been considered. For example, the  $\text{CO}_2$  emitted from fossil-fired smokestacks has much higher density than atmospheric  $\text{CO}_2$ , thereby simplifying  $\text{CO}_2$  extraction. While such an approach is not  $\text{CO}_2$  neutral, it could substantially reduce the net  $\text{CO}_2$  introduced into the atmosphere. Another approach that has been suggested is to extract carbon from the oceans, where the carbon content is much higher than in the atmosphere. This has been suggested as a potential approach for fuel synthesis at sea to support deployed naval forces. A brief discussion of this will be found in Coffey et al.<sup>7</sup> For these various approaches, as with the Stucki et al. and Green Freedom approaches discussed above, the regeneration of the  $\text{CO}_2$  upon extraction and the provision of the needed supplemental hydrogen for fuel synthesis will be energy intensive and have capital costs similar to those given above, because the same amount of  $\text{CO}_2$  must be regenerated, and the same amount of supplemental hydrogen must be provided.

## 10. Exploitation of Oil Shale

Production of liquids from oil shale appears on most lists of potential alternative transportation fuels. This is because there is a lot of oil shale. The most promising U.S. deposits are found in Wyoming, Utah, and Colorado. The most recent extensive assessment of the prospects for shale oil was published by the Office of Technology Assessment in 1980.<sup>28</sup> This assessment is still quite relevant.

While oil shale's organic content is relatively low (about 20% that of coal), the World Energy Council (WEC) puts U.S. proved recoverable and estimated recoverable oil from shale to be about  $6.5 \times 10^{11}$  barrels.<sup>29</sup> If this oil were recovered and used to meet the current annual U.S. petroleum requirement for transportation fuels, then the supply would last about 140 years. A 1.4% annual growth in demand would reduce that number to about 90 years, and a 5% annual growth in demand would reduce the time to depletion to about 50 years. These numbers indicate that oil shale is a significant potential source of transportation fuel.

The approach to fuels from oil shale is qualitatively different from the approaches discussed in the previous sections. Most of the organic content of oil shale is found in a substance called kerogen. Kerogen is not a member of the petroleum family and is not soluble in conventional petroleum solvents. As a result, it is not recoverable by solvent extraction. The standard practice for recovering oil from oil shale is to mine the shale, move it to a retort, and pyrolyze it. This practice is referred to as "surface retorting." The oil yield from this process has substantial variability, ranging from 10 gallons per ton to 60 (or more) gallons per ton of mined shale. Yields greater than 25 gallons per ton are believed to be required for economically viable production of shale oil.<sup>25</sup> If one assumes a yield of 30 gallons per ton, then it would be necessary to mine about  $2.3 \times 10^9$  tons of oil shale per year to meet current U.S. petroleum needs. This is about the same as the estimate given earlier regarding the amount of coal that would need to be mined to meet U.S. petroleum needs through the CTL process.

Since oil shale is predominantly inorganic, most of the mined material would have to be disposed of. The large volumes of shale needed to be mined and the need to dispose of a large waste stream have been major impediments to commercial exploitation of oil shale. This has led to several efforts to examine *in situ* retorting of the shale, where the shale would be pyrolyzed in place, thereby reducing the mining and waste disposal requirements. The basic idea is to drive out and condense the volatile components of the kerogen and extract the oils and gases by conventional petroleum retrieval schemes. One approach to this is to fracture the shale and combust the upper layer of the kerogen-containing shale, thereby forming a retorting and vaporization zone below the combustion zone. The vapor produced is condensed, and the resultant oil, water, and gases are pumped out. This process is more energy intensive than the surface retorting process but has the advantage of greatly reducing the waste disposal problem. It also raises considerable concerns regarding contamination of ground water. A variant of this scheme has been studied by Shell Oil corporation through its Mahogany Research Project.<sup>30</sup> In this scheme, electric heaters are inserted into the shale and gradually heat a volume of shale to about 700 °F. In order to keep the oil produced within a fixed volume,

the ground surrounding this volume is frozen. Tests were recently completed (2004) by applying this scheme to a small volume (about 1200 square feet of surface area). About 1700 barrels of light oils were recovered along with associated gases. Approximately one-third of the energy released was in the gases produced and two-thirds in the oil produced. This approach appears attractive, because it would seem to have a much lower environmental impact than the conventional techniques for recovering shale oil. Shell asserts that the process is less expensive than the conventional approaches for extracting shale oil.

It is informative to estimate the capital investment that would need to be made to recover the shale oil. In 1980 it was estimated (OTA) that a 50,000 barrel per day oil shale facility using underground mining and surface retorting would involve a capital cost of about 1.7 billion dollars (1980 dollars). If one simply scales that cost by inflation, one arrives at an estimate of about one trillion dollars (2005 dollars) for a 13.4 million barrel per day capability from surface retorting. This compares with an estimate of 900 billion dollar for producing the same quantity of oil equivalent liquid using the CTL or BTL approaches.

To the author's knowledge, there is no estimate available for the *in situ* approaches. However, one can gain some insight into the capital costs associated with the Shell approach. If the Shell approach to *in situ* retorting utilizes electric heating, then substantial capital costs will be associated with meeting the electric power demands. One can gain some insight into those capital costs by examining the power demands. Shell asserts that the energy return on energy invested (EROEI) for their process is about three. Most of the energy invested (EI) is associated with the electrical power needed to heat the shale. The energy returned (ER) represents the energy in the extracted oil and gas. A barrel of oil contains about  $6 \times 10^9$  Joules, and the United States consumes about  $13.4 \times 10^6$  barrels of oil per day for transportation purposes. If  $ER = 3EI$ , then these numbers imply that, in steady state, the energy invested per second would be about  $3.4 \times 10^{11}$  Watts. This is comparable to the average U.S. electric power consumption of about  $5 \times 10^{11}$  Watts. Considering the large amount of power needed and the remote locations of oil shale reserves, the Shell approach would likely require the construction of new generating capacity. If we assume that the power is supplied by power plants at a capital cost of  $\$1,500/\text{KW}_e$ , then the capital cost for providing the electrical generating capacity needed to heat the oil shale at the rate required to supply the current U.S. transportation demand would be about 500 billion dollars. This capital cost does not include the drilling and refrigeration capital costs. Thus, the 500 billion dollar cost estimate represents a lower bound on the actual capital cost. The further additional capital costs associated with oil and gas extraction should be similar to those that occur in traditional oil and gas extraction in the petroleum industry.

The prospects for generating the power required by the Shell *in situ* approach present some interesting challenges. For example, coal currently provides about half of the U.S. electricity supply. Thus, if coal were used to generate the electricity for the Shell process it would require tripling the current rate of coal production in the United States. The impact on the U.S. coal supply would be comparable to that of the CTL approach discussed earlier. Also, the capital costs associated with the substantial increase in coal

mining would need to be included in a proper capital cost estimate for an oil shale industry based on this approach.

As another alternative, one could consider a nuclear reactor approach to generating the electricity. This would involve building about 300 one gigawatt electric power nuclear reactors.

Another approach would be to make use of the gas that is generated by the *in situ* process itself. Approximately one-third of the energy returned is contained in that gas. Thus, its energy content would be produced at a rate of about  $3.4 \times 10^{11}$  Watts. If that power could be converted into electricity with 50% efficiency, it could provide about half the required electricity. Since the capital cost to construct a natural gas power plant is about half that required to construct a coal fired plant, the partial production of electricity from the *in situ*-produced gas would result in about a 25% capital cost saving for the electricity generation.

It is interesting to note that the *in situ*-produced gas contains about the same energy as that required by the *in situ* process. If gas burners could be inserted into the shale and the retrieved *in situ*-produced gas could be pumped into those burners and combusted, it could, in principle, provide the energy needed to power the *in situ* process thereby eliminating the capital costs associated with electricity generation. However, this approach, while energetically attractive, would likely greatly complicate the Shell concept. It would also eliminate a potentially valuable/marketable product of the *in situ* process.

Shell states that the energy returned (ER) by its process (oil and gas) divided by the energy invested (EI) to obtain the energy returned is 3. This should not be confused with the process efficiency calculated for the other processes considered. That efficiency would be the energy in the oil obtained divided by the sum of the calorific value of the kerogen that was pyrolyzed (35 MJ/kg times the number of kg pyrolyzed) plus the energy invested to accomplish that pyrolysis. We do not know from the Shell number how much of the energy in the kerogen was captured. However, we can put an upper limit on the process efficiency by assuming that ER represents all of the energy in the kerogen. Since Shell states that one-third of ER was in the gas product, we will assume that two-thirds of ER is in the oil product. In that case, it is a simple matter to show that the process efficiency would be 50%. This represents an upper limit on the process efficiency, because it is unlikely that all of the original kerogen will be captured. For example, if half of the kerogen is captured then the process efficiency would be about 25%. More data is needed to assess the efficiency of the Shell process.

# 11. Conclusion

A review is undertaken of several approaches to producing alternative transportation fuels using feedstocks that are under the control of the United States. The objective of the review is to provide the non-specialist reader with a general understanding of the several approaches, how they compare regarding process energy efficiency, their individual abilities to provide for national transportation fuel needs, and their associated capital costs.

It was found that, for all the propulsion plants considered, the specific energy of the plant decreases as the specific power of the plant increases. Batteries and fuel cells were shown to have a rapid decline in specific energy as specific power increased. As a result, there has been a very limited overlap between battery and fuel cell power and energy characteristics and transportation vehicle mission requirements. In some cases, where the mission requires high power for only a small fraction of a vehicle's mission, the introduction of an auxiliary pulse power system becomes viable. As a result, it is possible that battery and fuel cell technology combined with electric motors may progress to the point where this approach is viable for passenger vehicles where high power is typically required for less than 10% of a vehicle's mission. This could be an important development, because passenger vehicles account for about half of U.S. oil consumption. However, for high-energy, high-power missions, batteries and fuel cells are disadvantaged relative to the internal combustion engines considered. It seems unlikely that the disadvantage can be overcome for high-performance DOD, commercial, and industrial missions involving transportation fuels. As a result, internal combustion propulsion plants will likely remain the plants of choice for these missions.

The U.S. transportation sector consumes about 13.4 million barrels per day (BPD) of oil equivalent product. Consequently, this is the goal that was established for each alternative fuel process considered. The alternative fuel approaches considered include: hydrogen production, creation of synthesis gases from various feedstocks followed by a fuel synthesis process, enzymatic production of ethanol, the use of bio oils for biodiesel production, fuel synthesis using atmospheric carbon dioxide as a feedstock, and the exploitation of oil shale.

A quick summary of the findings for the various approaches considered is found in table 12. This table provides rough estimates of the process efficiencies and capital costs associated with production of hydrogen and the liquid fuels considered at a scale needed to produce  $13.4 \times 10^6$  BPD oil equivalent product. The table is ordered by increasing capital costs, except for oil shale, which is qualitatively different from the other entries.

Process	Process energy efficiency	ROM of capital cost (billions of dollars)	Comment
SMR to hydrogen	70%	173	Commercial process,* doubles NG consumption
Biodiesel	35%	200	Commercial process***
SMR to methanol	60%	250	Commercial process*
SMR to gasoline via methanol	54%	280	Commercial process*
Corn ethanol	46%	370	Commercial process***
Hydrogen by biomass gasification	46%	515	Commercial process**
Hydrogen by coal gasification	44%	525	Commercial process*, doubles coal consumption
Coal to liquid	44%	900	Commercial process*, quadruples coal consumption
Biomass to liquid	47%	900	commercial processes**
Hydrogen by thermochemical	50%	1,080	Process under development*
Lignocellulose ethanol	41%	1,467	Process under development**
Hydrogen by conventional electrolysis	25%	2,000	Commercial electrolyzer, 3'rd gen nuclear reactor*
Atmospheric CO <sub>2</sub>	18%	4,000	Commercial processes + 3'rd gen nuclear reactor*
Oil shale surface retort	?	1,000	Involves massive mining and disposal
Shell oil shale <i>in situ</i> retort approach	Less than 50%	Greater than 500	electric power plant only*

**Table 12.** Summary estimates of the process efficiencies and capital costs associated with production of hydrogen and several liquid fuels at a scale to produce  $13.4 \times 10^6$  BPD oil equivalent product.

Key: \*not renewable but can, in principle, meet the BPD goal, \*\*renewable but available feedstock cannot sustainably meet BPD goal, \*\*\*renewable but available feedstock cannot meet BPD goal ).

Several of the processes shown in table 12 can be eliminated. For example, corn-based ethanol and biodiesel have been included simply to show where they fall in the hierarchies of efficiency and cost. In reality, while both fuels may have important niche roles to play, neither of them is a serious candidate for solving the national transportation fuels problem. The necessary feedstocks are simply not available. It is also suggested to set hydrogen aside, even though it has the lowest capital costs when produced by SMR techniques. It could be used as a fuel if it were absolutely necessary and could be produced in adequate quantity to meet national transportation fuel needs. If produced by nuclear or solar-powered thermochemical means or electrolysis it would produce no CO<sub>2</sub>. However, the logistical problems associated with the cryogenic systems or high-pressure systems required to employ hydrogen as a general purpose transportation fuel make its use as a general purpose transportation fuel or as a fuel for most DOD vehicles problematic.

Among the remaining processes, the steam reforming of methane (SMR) processes are found to be the most energy efficient and to have the lowest capital costs. They can also produce a variety of different fuels, including hydrogen, alcohols, and hydrocarbons. Their use would double the consumption of natural gas and add substantially to CO<sub>2</sub> production. With regard to the increased consumption of natural gas, recent advances in the extraction of gas from shale using hydraulic fracture and the vast reserves of gas hydrates may play a role. The advances in extraction by hydraulic fracture have been estimated to increase the potentially available natural gas reserves by one-third, resulting in a U.S. natural gas supply of about 100 years at current usage rates. If gas hydrates could be safely and economically obtained, they would potentially provide a large supply of methane, thereby allowing the manufacture of transportation fuels for generations. It was found that, while SMR processes could supply the needed transportation fuels for an extended period, a number of issues must be resolved before the SMR approach to alternative fuel production can be properly assessed.

The next processes found to be most efficient and least capital intensive were the conversion of coal to liquid fuels (CTL) and the conversion of biomass to liquid (BTL). These processes are considerably more costly than the SMR processes. Nevertheless, they can produce a variety of fuels, including hydrogen, alcohols, and hydrocarbons. Their use would have significant impact on the coal and biomass resources of the United States. The CTL process could supply the needed transportation fuels for an extended period. The BTL process could produce about 30% of the needed transportation fuel in a sustainable fashion. The BTL process would be carbon neutral provided that no fossil fuel was used in growing and harvesting the biomass or in the BTL process itself. A number of issues must be resolved before either the CTL or BTL approach to alternative fuel production can be properly assessed.

The next process to appear in the efficiency and capital cost sorting is lignocellulosic ethanol production. This process attempts to break down the cellulose and hemicellulose in biomass into fermentable sugars. The process is still under development and is much more difficult and energy intensive than the well-developed corn ethanol process. However, if successful, it has the advantage that it can access a much larger feedstock than can the corn ethanol process. In order to function in a sustainable fashion, it would target the same 1.4 billion tons of biomass as does the BTL process. This amount of

biomass used as feedstock for the lignocellulosic ethanol process would yield about 30% of the ethanol required for a full solution. The capital investment required is estimated to be about 500 billion dollars. The situation regarding carbon neutrality is the same as for the BTL approach. The process has yet to be demonstrated at a scale where its contribution to alternative fuels can be properly assessed.

It was found that the fuel synthesis schemes with the lowest energy efficiency and the highest capital cost involve the use of atmospheric CO<sub>2</sub> as a feedstock. In principle, the process should be capable of producing the quantities of fuel needed to solve the transportation fuel problem. For the case considered herein, this would require about 1600 nuclear reactors, each providing a thermal power of about three gigawatts. The associated uranium consumption would be substantial and would deplete the reserves of high-grade uranium ore in a few decades. The long-term viability of such a process would likely involve the introduction of advanced reactors including breeder reactors. Similar approaches could be applied to converting smokestack CO<sub>2</sub> to fuel, where the higher CO<sub>2</sub> density would make the collection of CO<sub>2</sub> easier. However, for the same amount of fuel the plant capital costs would be similar to that given above for fuel production from atmospheric CO<sub>2</sub>. There are clearly many issues that need to be resolved regarding this approach to alternative transportation fuels.

The final topic considered was oil shale. It is estimated that U.S. oil shale formations could supply current U.S. fuel needs for more than 100 years. Studies done in the 1980s, when scaled to 2005 dollars, suggest that the capital costs associated with producing 13.4x10<sup>6</sup> BPD of oil shale crude by surface retorting would be about one trillion dollars. Shell Oil has been studying an *in situ* retorting approach in which the heat needed to drive out the oil shale crude is provided by electric heaters placed within the shale deposits. It was shown that the electrical power system needed to provide the heat necessary to produce 13.4x10<sup>6</sup> BPD of oil shale crude would itself have a capital cost in excess of 500 billion dollars. There are many environmental concerns (e.g., ground water contamination) associated with producing oil shale crude.

The above results suggest these conclusions about alternative fuels:

- If necessary, the United States can manufacture the transportation fuels it needs.
- The capital investments needed to manufacture fuels beyond petroleum will be substantial, regardless of the particular alternative fuel selected. In this regard, the SMR processes, because of their higher efficiencies and substantially lower capital costs, would seem to warrant special attention. Of course, the associated fuels are not carbon free or carbon neutral.
- The capital investments associated with the manufacture of carbon free or carbon neutral fuels will be especially large. Associated with the latter point is the reality that serious investment in alternative fuels will be difficult to obtain as long as low-cost petroleum is available.
- On the basis of national security needs, the DOD could argue to use appropriated funds to pay for the development of an alternative fuel to supply its 2% of national transportation fuel usage. Such an undertaking should be

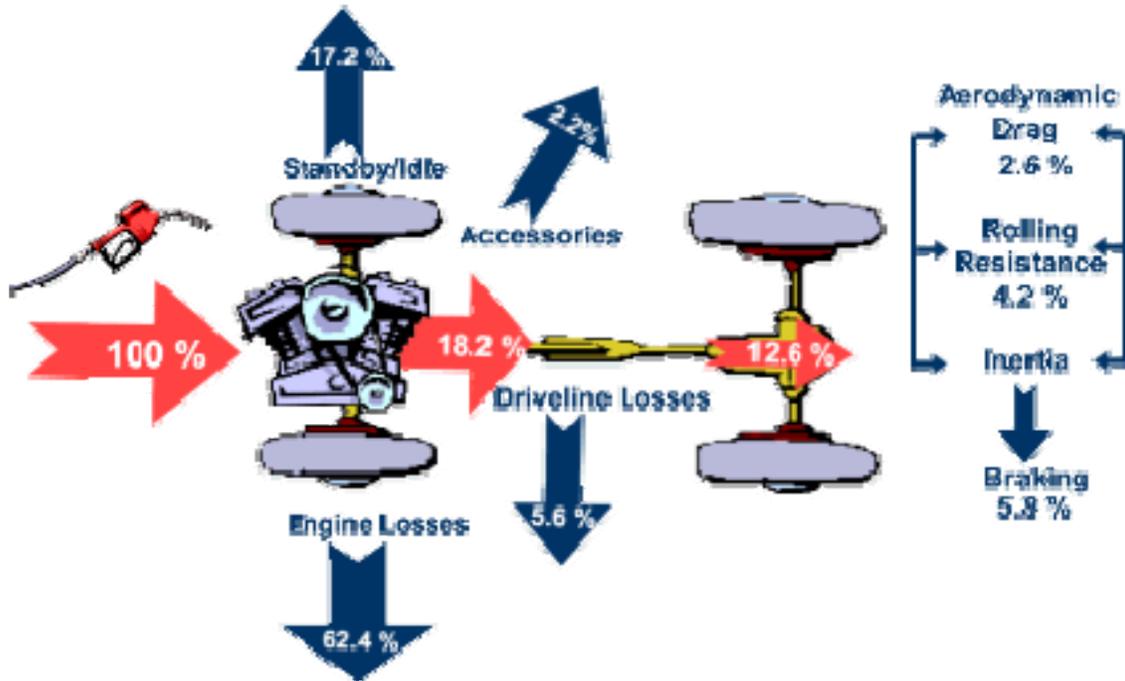
approached with great caution. If DOD selects a scheme that is not viable for the larger transportation system, then DOD will be left with a costly proprietary system, will be unable to benefit from competitive forces in the larger marketplace, and could find itself short of fuel in a time of national emergency.

It is certainly not clear at this time which is the best alternative fuel approach for DOD and for the nation. It will likely take decades to sort this out. DOD should be a participant in a national effort to clarify the choices from a perspective of mission requirements, to ensure that these will be met, because it could be impacted substantially by the outcome.

# Appendix A

## A Simple Model for Vehicle Kinematics

Figure A1 provides a simple illustration of how the energy flows through a typical land vehicle to provide the force needed to drive the vehicle.



**Figure A1.** A Simplified Accounting of Energy Flow in a Typical Vehicle Powered by an Internal Combustion Engine. (Source: <http://www.fueleconomy.gov/feg/atv.shtml>)

It is obvious from figure A1 that the energy actually needed to accomplish the vehicle's mission is a small fraction of the energy consumed by the vehicle. The power plant and its management are the principal reasons for this. If one could accomplish a significant improvement on the net energy conversion efficiency of the power plant it would have a great impact on the alternative fuels problem and the fuels problem in general. Furthermore, the ultimate energy and power needs are determined by a vehicle's mission rather than the fuel or the power plant. Therefore, it is helpful to be able to make simple estimates regarding how mission requirements relate to fuel requirements. An examination of figure A1 suggests that the motion of the vehicle along a straight line can be described by the following simple differential equation:

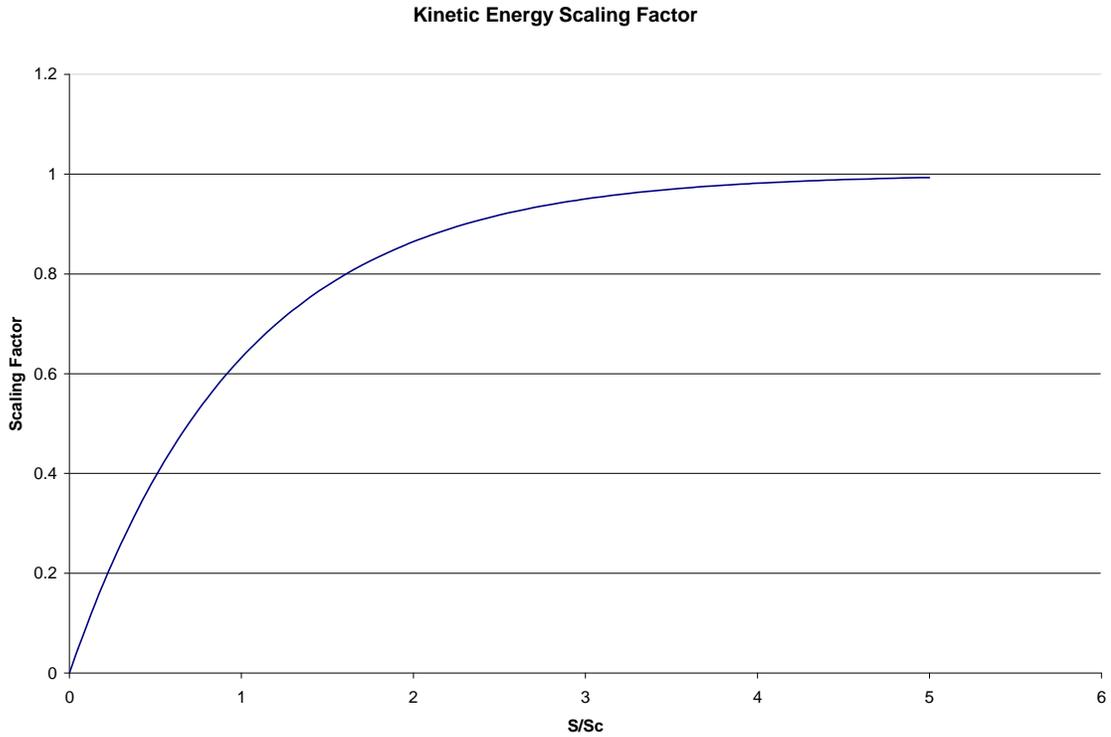
$$M \frac{dV}{dt} = MV \frac{dV}{dS} = F_p - F_R - F_D - F_G. \quad (A1)$$

Here  $M$  is the vehicle mass in kg,  $V$  is the vehicle speed in meters per second,  $t$  is the time in seconds,  $S$  is distance traveled in meters,  $F_p$  is the propulsion force in Newton,  $F_R$  is the rolling force,  $F_D$  is the drag force, and  $F_G$  is the component of the gravity force in the direction of motion. The rolling force can be expressed approximately as,

$F_R = C_R W$ , where  $C_R$  is the rolling coefficient and  $W$  is the vehicle weight. The drag force can be written as  $F_D = C_D \rho A V^2 / 2$ , where  $C_D$  is the drag coefficient,  $\rho$  is the fluid density,  $A$  is the appropriate area of the vehicle (frontal area for land vehicles, surface area for aircraft, wetted area for ships and submarines), and  $V$  is the velocity of the vehicle. The quantities  $C_R$ ,  $W$ ,  $C_D$ , and  $A$  are properties of the vehicle. For air vehicles, the drag force  $F_D = C_D \rho A V^2 / 2$  applies only at velocities where the parasitic drag dominates the induced drag. If we assume that the propulsion force is constant and the motion is along a straight line, then it is straightforward to show that the following simple relationship between the vehicle velocity and the distance traveled applies:

$$\frac{1}{2} M V^2 = (F_P - F_G - C_R W) S_c \left[ 1 - K e^{-S/S_c} \right]. \quad (\text{A2})$$

Here,  $K$  is a constant that is determined by the initial conditions placed on  $V$  and  $S$ . The characteristic length  $S_c = M / C_D \rho A$  depends on the vehicle properties and the density of the fluid in which it moves. We will call the expression in square brackets the kinetic energy scaling factor. For simplicity, we will assume that  $K = 1$  (i.e., the velocity is zero when  $S = 0$ ). For this case, the kinetic energy factor is plotted in figure A2.



**Figure A2.** Kinetic energy scaling factor when  $K = 1$ .

Several things are evident from eq. (A1) and figure A2. First, for there to be any forward motion, the propulsion force must exceed the sum of the gravitational force and the rolling force. Second, for a fixed propulsion force, there is a maximum velocity that

can be achieved. This maximum velocity is achieved when  $S$  is much greater than  $S_c$ . This region generally establishes the power required for constant velocity travel by land or by sea vehicles. A similar result holds for aircraft, but the calculation is more complicated due to the presence of induced drag. Finally, when  $S$  is much less than  $S_c$ , the kinetic energy is proportional to  $S$ . This is a region of constant acceleration. For land vehicles, this region usually establishes the size of the propulsion plant.

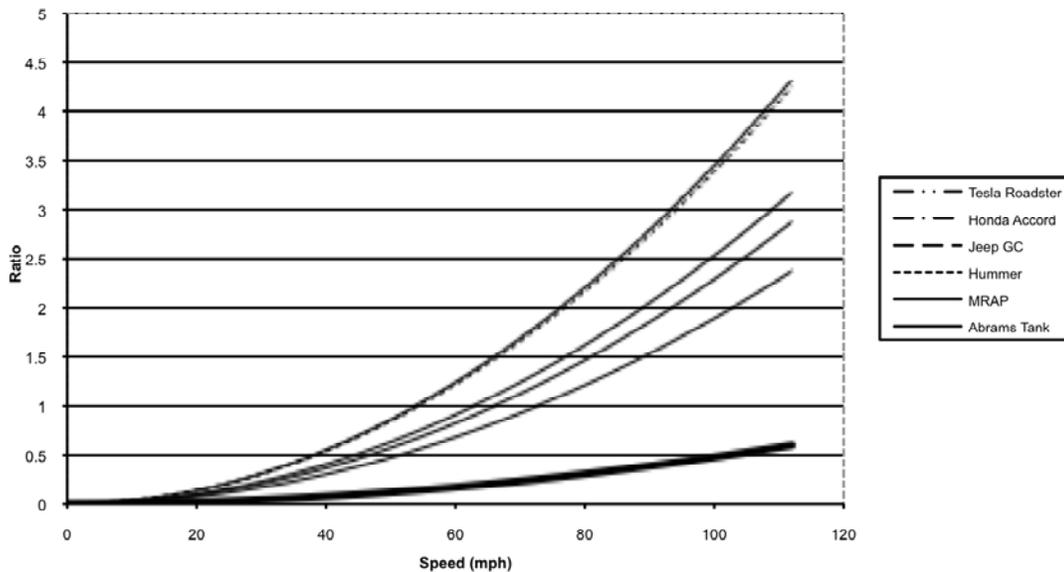
In order to make use of eq. (A1), it is necessary to specify the various parameters on which the equation depends. For land vehicles, table A1 provides some approximate values for the parameters of several vehicles. The vehicles have been selected to cover the range from passenger vehicles to heavy armored vehicles.

Vehicle	Weight (lbs)	Mass (kg)	Available Horse-power	$C_R$ (asphalt surface)	$C_D$	$A$ (m/s)	$S_c$ (m)	$F_R$ (N)
Tesla Roadster	2723	1237	288	.03	.35	2	1473	364
Honda Accord	3300	1500	270	.03	.35	2	1786	441
Jeep Grand Cherokee	4470	2032	195	.03	.45	2.8	1334	598
Hummer	6600	3000	300	.03	.6	4	1041	883
MRAP	38,000	17,000	400	.02	.8	12	1500	3,300
Abrams Tank	140,000	63,000	1500	.04	.8	12.4	5292	25,000

**Table A1.** Approximate Values of Parameters Characterizing Several Land Vehicles.

From table A1 and eq. A1, one can estimate the velocities at which the drag force becomes significant relative to the rolling force. Figure A3 provides the ratio of the drag force to the rolling force as a function of speed.

Figure A3. Ratio fo Drag Force to Rolling Force vs Speed (mph) for Several Vehicles



It is clear from figure A3 that the rolling force dominates up to speeds of about 40 mph for all the vehicles considered. One must exceed 60 mph for the drag force to become dominant. For the Abrams tank, the rolling force dominates over all speeds of interest (the Abrams has a maximum governed speed of 42 mph). The rolling force results primarily from energy lost in deforming the materials in tires, treads, and the surface on which a vehicle travels. The results presented in figure A3 are for travel over an asphalt surface. The MRAP and the Abrams have about the same drag force, but the Abrams has a much larger rolling force. This is partly due to the larger weight of the Abrams, but it is also due to the lower value of  $C_R$  for the rubber-wheeled MRAP as opposed to the tracked Abrams. Fuel consumption is related to the speed multiplied by the sum of the drag and rolling forces. One can conclude from figure A3 and table A1 that, for travel on hard surfaces, wheeled vehicles will consume less fuel per pound than will tracked vehicles. However, for travel on soft surfaces, such as sand, the value of  $C_R$  increases much more rapidly for wheeled vehicles than for tracked vehicles, and fuel consumption should be lower for tracked vehicles. This points to the obvious reality that judging fuels and fuel consumption is very dependent on mission and whether one is engaging in peacetime operations or wartime operations.

Table A1 indicates that the characteristic length  $S_c$  is measured in kilometers for the vehicles considered. In general, one wants to reach the upper speed range of a vehicle in distances less than  $S_c$ . The power that must be provided at velocity  $V$  is just  $VF_p$ . When  $S \ll S_c$ , the kinetic energy factor is just  $S/S_c$ . The power that must be provided at velocity  $V$  is just  $VF_p$ . It follows from eq. (A2) that, when  $S \ll S_c$ , the effective horsepower  $HP_e$  needed to reach a velocity  $V$  in a time  $t$  is

$$HP_e = 1.34 \times 10^{-3} \left( \frac{MV^2}{t} + F_R V \right). \quad (A3)$$

The factor in front of the square brackets is the conversion factor from Watts to horsepower. The effective energy  $E_e$  required to accomplish the acceleration is just

$$E_e = \frac{1}{2} [MV^2 + S(F_R + F_G)], \quad (A4)$$

where  $S = Vt/2$  is the distance traveled during acceleration. The energy  $E_e$  is expressed in Joules. Equations (A3) and (A4) can be used to calculate  $HP_e$  and  $E_e$  if  $V$  and  $t$  are specified or to calculate  $t$  and  $E_e$  if  $V$  and  $HP_e$  are specified. These calculations may be done with a hand calculator.

It should be noted from eq. (A4) that the energy expended to overcome the rolling force is proportional to  $t$ . Hence, a shorter acceleration time results in less energy loss. However, the power given by eq. (A3) contains a term that is proportional to  $t^{-1}$  leading to the result that faster acceleration requires more power and hence a larger power plant in the vehicle. The tradeoff between these competing effects becomes significant for heavy military vehicles.

If one applies eq. (A3) to the vehicles listed in table A1 and calculates the horsepower needed to accelerate these vehicles to 60 mph in 6 seconds and the time to accelerate to 60 mph with the horsepower available to each vehicle, one obtains table A2.

Vehicle	Horsepower needed to go from 0 to 60 mph in 6 seconds	Time (s) to go from 0 to 60 mph with available horsepower
Tesla	215	4.4
Honda Accord	252	5.76
Jeep GC	363	11.5
Hummer	520	12.5
MRAP	2,887	67
Abrams	11,661	103

**Table A2.** Horsepower needed to go from 0 to 60 mph in 6 seconds and time to reach 60 mph with available horsepower for acceleration over level ground.

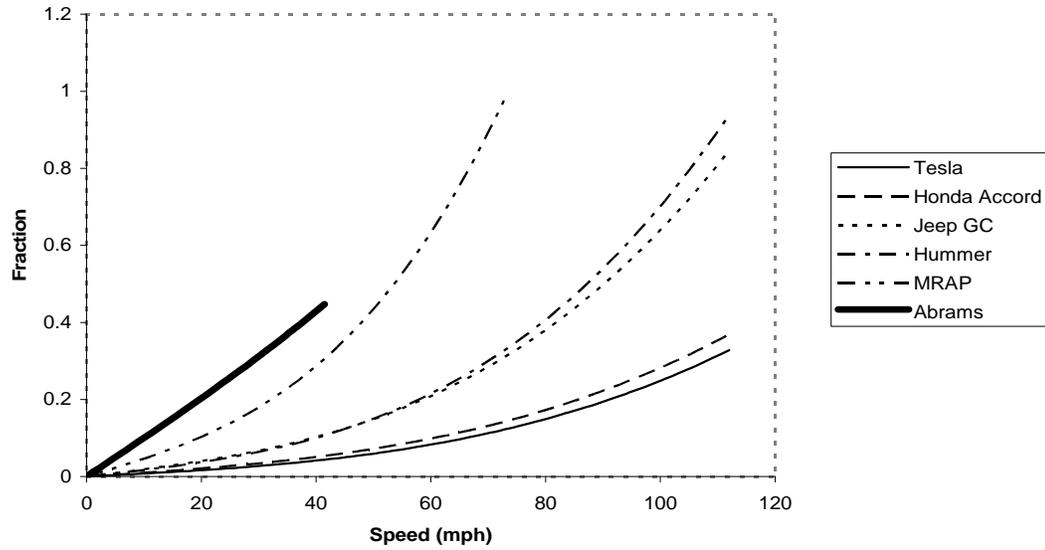
Only the Tesla Roadster and the Honda Accord have the horsepower required to travel from 0 to 60 mph in 6 seconds. The other vehicles are underpowered to meet this objective. The third column in table A2 provides an estimate of the time it would take to reach 60 mph with the horsepower available to the various vehicles “as-built.” As mentioned above, the Abrams tank, while it has the horsepower to reach 60 mph, is not permitted to travel faster than 42 mph.

When  $S/S_c \gg 1$ , It is evident from fig A2 that the kinetic energy, and hence the velocity, reaches a constant value independent of distance. This region determines the horsepower needed to maintain a constant speed. In this case the horsepower can be written as

$$HP_e = 1.34 \times 10^{-3} \left[ \frac{1}{2} \frac{MV^3}{S_c} + (F_G + C_R W)V \right]. \quad (A5)$$

Fig A4 plots the fraction of the available horsepower needed to maintain speed versus the speed for the several vehicles listed in table A1.

**Figure A4. Fraction of Available Horsepower Needed to Maintain Speed vs Speed (mph) for Several Vehicles**



It is clear from figure A4 that, with the exception of the MRAP, the horsepower available to each vehicle is larger than that needed to maintain a particular speed. Since the MRAP has a maximum speed requirement of about 70 mph, the full horsepower is required to maintain that speed. For most vehicles, the engines are oversized for the cruising requirement. For example, the average speed traveled by private automobiles is about 45 mph. At that cruising speed, the Honda Accord uses about 6% of its available horsepower. The power plants for these vehicles are set by the acceleration requirements expressed through eq. (A3) and not by the cruising speed requirements.

Equation A1 can shed some light on the energy and power requirements associated with seagoing vehicles. To illustrate, we will consider surface vessels with displacement hulls. In this case, the rolling force is zero and, for our purposes, the gravity force can be taken as zero. The density that enters the characteristic length is  $\rho = 1000$ , and the area  $A$  is the wetted area of the vessel. For analytical simplicity we will use a formula for  $A$  developed by David Taylor:

$$A = 2.6(\Delta L)^{\frac{1}{2}}. \quad (A6)$$

Here  $\Delta$  is the ship displacement in tons and  $L$  is the ship waterline length in meters. The length  $L$  will be taken as 85% of the ship length. The Taylor formula is limited in accuracy but will suffice for the estimates desired here. It would be helpful to have a simple analytical relationship between ship length  $l$  and its displacement  $\Delta$ . In this regard, an examination of the displacement and length data for a variety of cargo ships and fast ships finds that the data is well encompassed by two curves of the form

$$\Delta = \alpha l^3. \quad (\text{A7})$$

The choice  $\alpha = .0098$  is representative of the larger cargo ships. The choice  $\alpha = .002$  is representative of the fast ships, such as combatants and fast cruise ships. We will refer to these as fast ships. If we use this relationship between  $\Delta$  and  $l$ , then the Taylor formula becomes

$$A = 2.4\alpha^{1/2}l^2. \quad (\text{A8})$$

.The drag force becomes

$$F_D = 12000C_D\Delta^{2/3} / \alpha^{1/6}. \quad (\text{A9})$$

For cargo ships we will set  $C_D = 4 \times 10^{-3}$ . This value is taken from Lin et al.<sup>3</sup> The effective horsepower needed to maintain a ship at speed  $V$  is just the product of  $F_d$  and  $V$ . Using this data, figure 4 provides estimates for the required effective horsepower vs. desired maximum speed for cargo ships in the length range 150–400 meters

As a point of comparison, the VLCC tanker *Frank A Shrontz* with a length of about 330 meters and a cruising speed of 16 knots has a power plant of about 34,000 horsepower. This is in reasonable agreement with the predicted value obtained from figure 4 and suggests that the power plants chosen for cargo ships are selected to be close to the power needed to maintain a desired cruising speed. Similar calculations can be done for fast ships when the appropriate values of the drag coefficient and wetted surface areas are known.

# Appendix B

## The Gasification and Fischer-Tropsch Processes

For the purpose of illustration, this appendix considers a specific example of a Fischer-Tropsch reactor fed by a coal gasifier. The basic FT synthesis process proceeds according to the reactions

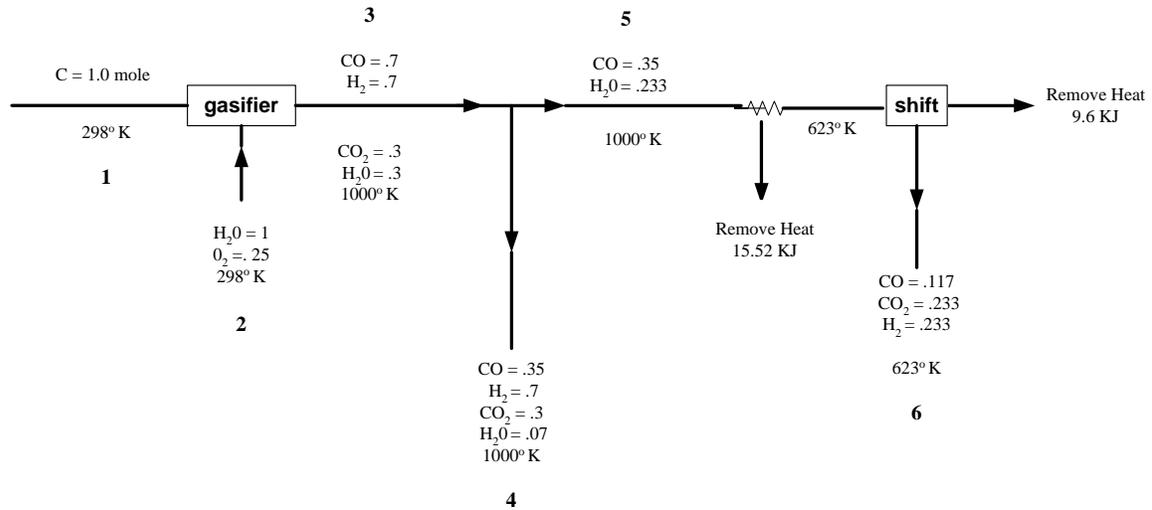


The first reaction produces olefins, or alkenes, ( $C_nH_{2n}$ ) while the second reaction produces paraffins, or alkanes, ( $C_nH_{2n+2}$ ). As an example, when  $n = 8$ , the reader will recognize the paraffin product as octane. The FT process always produces a mix of olefins and paraffins. However, the details of the mix depend on the reactor conditions and the catalyst used. The FT reactors are generally operated in a low temperature range of 200–240 °C or a high temperature range of 300–350 °C. Low-temperature operation favors high molecular weight waxes, while high-temperature operation favors low molecular weight olefins. The route to diesel fuel is through the low-temperature process, while the route to gasoline is the high-temperature process. In both cases, product upgrading is required.

A typical source of the carbon monoxide (CO) and hydrogen needed by the FT reactor is a gasifier. Because of the central roles that gasification and Fischer-Tropsch chemistry play in the study of alternative fuels, this topic is discussed here in somewhat more detail than others in this paper. The discussion will still be elementary. A more thorough discussion of gasification can be found in Probst and Hicks.<sup>2</sup>

For this example, consider a gasifier that can produce a syngas with a  $H_2/CO$  ratio of 2:1, which it achieves by converting a substantial fraction of the available CO to  $CO_2$ . Although the ratio of 2:1 is necessary for the olefins FT process, this greatly reduces the total quantity of CO in the feedstock. There is, therefore, a tradeoff between achieving the desired ratio and the absolute amount of CO available for the FT process. To the extent that the  $H_2/CO$  ratio is less than 2:1 it will be necessary either to burn additional coal or to provide supplemental hydrogen in order to produce the needed quantity of desired product.

The actual amount of CO and hydrogen available is determined by the chemical kinetics that occur in the gasifier. For the application considered here, a gasifier works by combusting a fraction of the available carbon and using the released energy to raise and heat steam and carbon to a temperature where the production of CO and  $H_2$  is optimized. In this regard, a temperature of 1000 °K is appropriate. In figure B1 we provide an oversimplified illustration based on equilibrium chemistry for the case where one mole (12 grams) of carbon is gasified using .25 mole (8 grams) of oxygen and 1 mole (18 grams) of water.



**Figure B1.** Mass flowchart (units in moles) from the gasifier through the water-gas shifter.

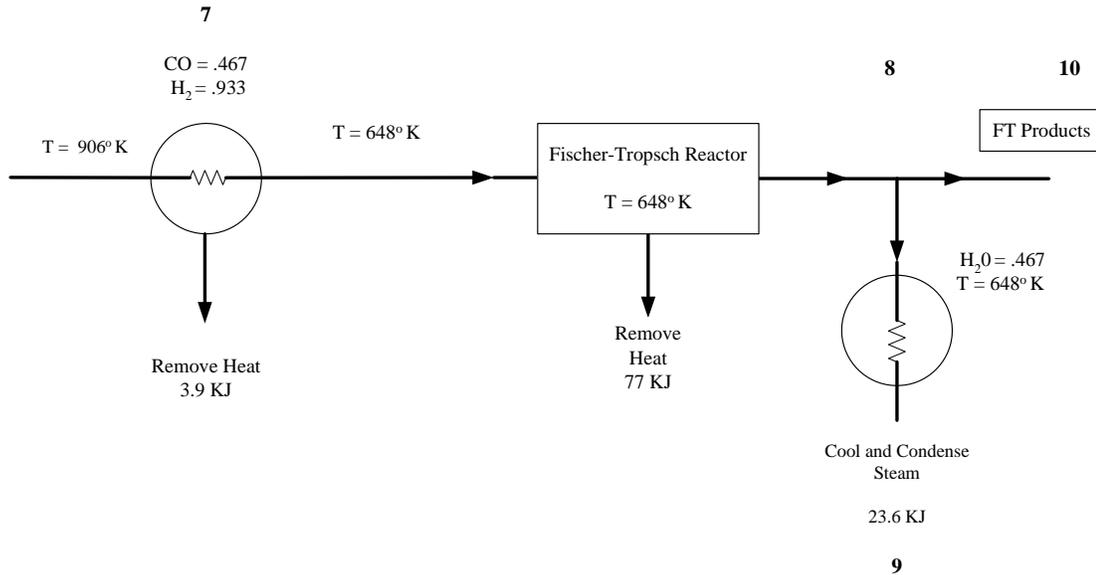
For the moment, we will consider only streams 1, 2 and 3 of figure B1. The combustion of .25 mole of carbon with .25 mole of oxygen produces 98.6 KJ of heat energy. This is adequate to raise and heat the 1 mole of steam and the remaining .75 mole of carbon to 1000 °K. In this particular example, the gasification reactions that lead to stream 3 will not greatly alter the energy balance. In general, if the gasification reactions lead to an energy deficit regarding maintaining the desired temperature, then additional energy would have to be added. Similarly, if the gasification reactions produced energy excess to maintaining the desired temperature, then energy would have to be removed. Excess energy could, in principle, be reused, for example, to raise steam or to generate electricity.

The gasifier outlet stream 3 contains only half the hydrogen needed to satisfy equations (B1) and (B2). This means that only one half of the carbon in stream 3 can be converted via the FT process. This is very wasteful in the use of carbon (e.g. coal). Some improvement can be made by introducing an additional step that employs the water-gas shift reaction



Figure B1 illustrates the use of the shift reaction by separating stream 3 into stream 4 and stream 5. Stream 4 contains all of the hydrogen from the gasifier and half the carbon monoxide. The remaining carbon monoxide and sufficient steam is separated into stream 5 such that the output of the shift reactor (stream 6) will contain the proper ratio of hydrogen to carbon monoxide. The catalyst in the shift reactor works best at 623 °K. This requires that heat (15.5 KJ) be removed from stream 5. Since the shift reaction is exothermic, heat (9.6 KJ) must also be removed from the shift reactor in order to maintain its temperature. The excess heat from stream 5 and from the shift reactor can, in principle, be reused.

If one separates out and combines the carbon monoxide and hydrogen in streams 4 and 6, one is left with a combined stream containing .933 mole of hydrogen and .467 mole of carbon monoxide. This approximately satisfies equation 2. Therefore, the gasifier-shifter arrangement shown in figure B1 would provide 47% of the carbon that entered the gasifier to the FT synthesis unit. Figure B2 provides an oversimplified mass flow chart beginning with the combined stream (stream 7) through the FT reactor.



**Figure B2.** Mass flow chart (flow units in moles) from the water-gas shifter through the FT reactor.

The FT reactor prefers to operate at a temperature of 648 °K. This requires that 3.86 kJ of heat be removed from stream 7. Furthermore, the FT reaction is exothermic. In order to maintain the FT reactor temperature at 648 °K it is necessary to remove 77 kJ of heat from the reactor. The FT reactor is the largest source of excess heat in the example considered here.

The FT reactor generally produces a mixture of compounds. The liquid fuel fraction has a maximum selectivity of about 50%. At this selectivity, about 25% of the carbon that entered the gasifier would exit the FT synthesis unit as gasoline or diesel. This implies that one ton of carbon (coal) produces about .29 tons, or 2 barrels, of oil equivalent liquid. This is in agreement with industrial experience with the coal to liquid (CTL) process. Therefore, about  $2.2 \times 10^9$  tons/year of coal would be needed to provide the liquid fuel to replace conventional petroleum using the CTL process. From an energy efficiency perspective, it should be noted that one ton of coal has a calorific value of about 28 GJ while two barrels of gasoline have a calorific value of about 12.2 GJ. This results in a net calorific efficiency of about 44% for the CTL process. There is the potential to improve this efficiency by utilizing some of the waste heat that is evident in figures B1 and B2. The excess heat identified in these figures is about 130 kJ. If 50% of this energy could be

recovered and used to generate electricity, then the net calorific efficiency would rise to about 57%.

One can gain some understanding of the total power flow that would be involved in a CTL solution of the national transportation fuels problem by scaling from the 12 grams of carbon used in the example above to the needed  $2.2 \times 10^9$  tons/year ( $6.3 \times 10^7$  gm/sec). In this case, the thermal power associated with carbon combustion is  $5.2 \times 10^{11}$  Watts. This corresponds to 170  $3\text{GW}_{\text{th}}$  coal gasifiers. The thermal power associated with the waste heat identified in this simple example would be about  $7 \times 10^{11}$  Watts. Since the average U.S. electrical power usage is about  $5 \times 10^{11}$  Watts, there would be a high priority placed on making use of the waste heat from CTL plants associated with a solution to the national transportation fuels problem.

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